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DEVELOPING FAULT MANAGEMENT IN A DISTRIBUTION MANAGEMENT SYSTEM BASED ON REQUIREMENTS OF FINNISH DISTRIBUTION SYSTEM OPERATORS

Master of Science Thesis

Examiner: prof. Pekka Verho
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ABSTRACT

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Fault management is one of the key parts of the network operation process, especially for rural Distribution System Operators. Efficient fault management is highly dependent on the Network Control Center and the operators that are responsible for the network. One of the most important tools used in fault management is the Distribution Management System and therefore it is vital that it offers adequate features to manage the different fault situations. Developing these tools and ensuring that they are compliant with the requirements and needs of the customers requires interaction with the DSOs. The main objectives of this thesis were to gather the most recent development ideas and requirements from Finnish DSOs, regarding ABB MicroSCADA Pro DMS600 and to provide implementation specifications for the most important ones. One of the objectives was also to describe the fault management processes and analyse the current fault management features of the system by simulating actual faults.

The fault simulations were carried out in a replicated environment of a certain DMS600 customer and they focused mainly on testing the automatic fault isolation and restoration feature and the fault location function that is closely related to it. According to the simulations, fault locations are rarely available and therefore the current automatic fault isolation and restoration feature is not feasible, although the switching sequences generated were mostly correct. Thus, no significant monetary benefits can currently be expected from the use of the feature but, according to the simulation results, a new automatic fault isolation and restoration feature with a redesigned logic could provide considerable reductions in the annual KAH-value. The main part of this thesis, the customer interviews, were carried out by interviewing three largest DMS600 customers. A semi-structured interview method was used and a basic structure for the interviews was provided but mostly the interviews consisted of open discussion. Numerous development ideas and requirements were presented in the interviews. The most important ones were the new automatic fault isolation and restoration feature and the new fault prioritization tool. This thesis also describes the fault management processes of the interviewed DSOs. The final part of this thesis provides specifications for the new fault prioritization tool and an automatic fault reporting feature that were chosen for implementation analysis. Future developments, regarding e.g. the new automatic fault isolation and restoration feature and some other minor, but viable additions and changes were also introduced in the final part of this thesis.

TIIVISTELMÄ

JUSSI KONSTI: Vianhallinnan kehittäminen käytöntukijärjestelmässä suomalaisten sähköverkkoyhtiöiden vaatimuksiin perustuen
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Avainsanat: käytöntukijärjestelmä, KTJ, vianhallinta, käytönvalvontajärjestelmä, KVJ, sähköverkkoyhtiö, vikojen priorisointi, vian paikannus, automaattinen vian rajaus ja jakelun palautus, automaattinen vian raportointi

Vianhallinta on tärkeä osa verkon käyttötoimintaa, etenkin sähköverkkoyhtiöille, jotka toimivat haja-asutusalueilla. Tehokas vianhallinta on vahvasti yhteydessä käyttökeskuksen ja sitä hallinnoivien verkko-operaattorien toimintaan vikatilanteessa. Eräs tärkeimmistä operaattorien käyttämistä työkaluista vianhallinnan aikana on käytöntukijärjestelmä ja siksi on tärkeää, että se tarjoaa asianmukaiset toiminnot kuhunkin vikatilanteeseen. Asiakkaiden tarpeita vastaavien vianhallintatoimintojen kehittäminen vaatii kuitenkin vuorovaikutusta sähköverkkoyhtiöiden kanssa. Tämän työn tärkeimpänä tavoitteena olikin kerätä viimeisimmät vaatimukset ja kehityskohteet vianhallinnalle ABB MicroSCADA Pro DMS600 –käytöntukijärjestelmässä sekä luoda tarkemmat määrittelyt tärkeimmille uusille ominaisuuksille, jotka implementoidaan järjestelmään lähiaikoina. Työn tavoitteena oli myös kuvata DMS600-asiakkaiden vianhallintaprosessit ja analysoida järjestelmään jo sisältyviä vianhallintatoimintoja simuloimalla todellisia jakeluverkon vikoja.

Vikasimuloinnit toteutettiin erään DMS600-asiakkaan kopioidussa ympäristössä ja ne keskittyivät pääasiassa automaattisen jakelunpalautussekvenssin sekä siihen vahvasti liittyvän vianpaikannustoiminnon testaukseen. Simulointien perusteella viat pystytään harvoin paikantamaan sillä tarkkuudella, että nykyistä jakelunpalautussekvenssiä pystyttäisiin käyttämään, vaikkakin järjestelmän luomat kytkentäsekvenssit olivat enimmäkseen käyttökelpoisia. Tästä johtuen merkittäviä rahallisia hyötyjä ei voida saavuttaa nykyisen toiminnon avulla, mutta uusi, erilaiseen toimintalogiikkaan perustuva automaattinen vianrajaustoiminto sen sijaan voisi mahdollistaa varteenotettavat säästöt sähköverkkoyhtiöiden vuosittaisessa KAH-kertymässä. Työn ydinosa koostuu asiakashaastatteluista ja niiden pohjalta luoduista uusien ominaisuuksien määrittelyistä. Haastattelujen toteuttamiseksi työn aikana vierailtiin kolmen suurimman DMS600-asiakkaan luona ja menetelmänä käytettiin teemahaastattelua, jossa haastattelun perusrakenne oli laadittu etukäteen, mutta keskustelu tilaisuuden aikana oli muuten avointa. Haastattelujen tuloksena saatiin useita kehityskohteita, joista tärkeimpinä esille nousivat uusi vianrajaustoiminto sekä vikojen priorisointityökalu. Lisäksi työssä kuvattiin myös haastateltujen asiakkaiden vianhallintaprosessit. Työn viimeisessä osuudessa luotiin määrittelyt uudelle vikojen priorisointityökalulle sekä automaattiselle vikaraportointitoiminnolle, jotka valittiin tarkempaan tarkasteluun implementointia varten. Lisäksi työn viimeisessä osassa esiteltiin asiakashaastatteluihin ja simulointeihin perustuen toteuttamiskelpoisimmat jatkokehitystarpeet vianhallinnalle, joista tärkeimmäksi nähtiin uusi vianrajaustoiminto.

PREFACE

This Master of Science Thesis was written for the Grid Automation Systems product group of Power Grids division at ABB Oy between December 2016 and September 2017 and the topic was originally proposed by M.Sc. Ilkka Nikander from ABB Oy in November 2016. The examiner of the thesis at Tampere University of Technology was Professor Pekka Verho and the supervisor at ABB was M.Sc. Teemu Leppälä.

First, I want to express my gratitude to Teemu Leppälä, for continuous and clear guidance and valuable advice throughout the process. It was always easy to ask for your guidance during the process. I also want to thank Ilkka Nikander for the opportunity to write this thesis for ABB and learn great many new things. Thanks also to Pekka Verho for the insights and comments regarding the thesis. In addition, thanks to Matti Pesonen, Matti Karhinen and Olli Turunen from PKS Sähkönsiirto Oy, Sami Viiliäinen and Timo Kiiski from Savon Voima Verkko Oy and Juhani Liljanko and Mika Huttu from Järvi-Suomen Energia Oy for participating in the interviews and sharing valuable information and insight for this thesis. I also wish to express my gratitude for all the personnel at ABB who contributed to this thesis.

Finally, thanks to my friends and family for the constant support and patience during the thesis process. Particularly important has been the daily support and encouragement of my beautiful and intelligent long-term girlfriend Janna and therefore she deserves a special recognition; without you I could not have completed this project.

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LIST OF SYMBOLS AND ABBREVIATIONS

ABB	Asea Brown Boveri
AMR	Automatic Meter Reading
CIS	Customer Information System
DAR	Delayed Auto-Reclosing
DMS	Distribution Management System
DMS600	ABB MicroSCADA Pro DMS600
DMS600 WS	ABB MicroSCADA Pro DMS600 Workstation
DMS600 NE	ABB MicroSCADA Pro DMS600 Network Editor
DRRC	Distribution Reliability Requirement Class
DSO	Distribution System Operator
CaCe	Tieto Care Center
CAIDI	Customer Average Interruption Duration Index
FLIR	Fault Location, Isolation and power Restoration
GOOSE	Generic Object Oriented Substation Event
GPRS	General Packet Radio Service
GPS	Global Positioning System
GSM	Global System for Mobile Communications
GUI	Graphical User Interface
HSPA	High-Speed Packet Access
IEC	International Electrotechnical Commission
HV	High Voltage
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
IT	Information Technology
JSE	Järvi-Suomen Energia Oy
KAH	Keskeytyksestä Aiheutunut Haitta, Regulatory outage costs
LTE	Long Term Evolution
LV	Low Voltage
MAIFI	Momentary Average Interruption Duration Index
MED	Major Event Day
MDMS	Meter Data Management System
MRS	Meter Reading System
MS	Microsoft Corporation
MV	Medium Voltage
NCC	Network Control Center
NDE	Non-Delivered Energy
NIS	Network Information System
ODBC	Open Database Connectivity
OPC	OLE for Process Control
PG	Tieto PowerGrid NIS
PKS	PKS Sähkönsiirto Oy
PLC	Power Line Carrier
RAR	Rapid Auto-Reclosing
RCD	Remote-Controlled Disconnector
RNO	Regional Network Operator
RTU	Remote Terminal Unit

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCB	Sectionalizing Circuit Breaker
SMS	Short Message Service
SVV	Savon Voima Verkko Oy
SQL	Structured Query Language
NCC	Network Control Center
TAM	Telephone Answering Machine
TCP	Transmission Control Protocol
UMTS	Universal Mobile Telecommunications System
UPS	Uninterruptible Power Source
VPN	Virtual Private Network
WiMAX	Worldwide Interoperability for Microwave Access
WMS	Work Management System
XML	Extensible Markup Language

1. INTRODUCTION

During the recent years, heavy investments in the Finnish electricity distribution networks have been made in attempt to create a weatherproof distribution system. According to [1] over 8.6 billion euros will be invested in distribution networks by the end of 2029. Although it is apparent that the reliability of the network will eventually improve, the renewal process is slow, and in the meanwhile, Distribution System Operators (DSOs) must seek cost savings also by other means. No significant reductions in the system average interruption durations or standard compensations paid can yet be seen [2, p. 39] and it is likely that the distribution networks will remain at least somewhat vulnerable to weather conditions for at least the next decade. Thus, fault management is still an important topic, especially for rural DSOs. At the center of fault management is the Network Control Center (NCC) and the operators that run it. One of the key tools used in fault management at NCC level is the Distribution Management System (DMS) that provides numerous functionalities to support the operator in fault situations. The most widely used DMS among Finnish DSOs is the ABB MicroSCADA Pro DMS600 (DMS600). While DMS600 already provides numerous features for fault management, the DSOs requirements and preferences evolve over time when the Energy Authority changes the regulation model and more and more information becomes available from the primary process. Modifications to the existing features could be needed or completely new features might be considered necessary. Therefore, this thesis aims to gather the most recent requirements and ideas from Finnish DMS600 customers and also to provide specifications for some features that are most viable for implementation.

The primary objective of this thesis is to gather development needs and requirements from Finnish DSOs, identify the most important ones and then create specifications for those that are chosen for implementation. The development needs and requirements will be gathered by interviewing representatives of the three largest Finnish DMS600 customers as a comprehensive study, covering all Finnish DMS600 customers would be too laborious within the scope of this thesis. Thus, a semi-structured interview, focusing on the representatives of the three largest DMS600 customers will be used in the interviews. One of the objectives is also to first study the feasibility of the fault management functions already included in DMS600 by simulating actual, historical faults in a replicated environment of a certain DMS600 customer. In addition, to improve understanding of the DMS600 usage situation during fault management in customers' environment, a secondary objective is also to describe the fault management processes of DMS600 customers and the most important features of DMS600 during fault management. While the operating environments of DSOs may vary significantly, this thesis focuses mainly on the needs and requirements of DSOs operating in rural areas and urban networks are left to minor notice. In addition, only the fault management features of DMS600 and improvements related to them are considered in this thesis.

The first part of the thesis introduces the electricity distribution business in Finland, typical distribution automation available in Finnish distribution networks and fault situations and fault management in general. DMS600 will also be introduced more thoroughly in this part. The second part consists of the fault simulations and customer interviews. The fault simulation part mainly focuses on testing the automatic fault isolation and restoration feature and the fault location function that is closely related to it. Also some estimations of the potential benefits achievable from the use of these features are presented. The interviews of the DMS600 customers form a core part of this thesis. The three DSOs that participated in the interviews were PKS Sähkönsiirto Oy, Savon Voima Verkko Oy and Järvi-Suomen Energia Oy, all large DSOs operating in mostly rural areas. The development needs and requirements gathered are thoroughly described in the second part of the thesis, along with the fault management processes of each interviewed DSO. Finally, the last part of the thesis describes specifications for two of the most important new features that were chosen for implementation analysis; a *fault prioritization tool* and an *automatic fault reporting feature*. The focus is especially on the fault prioritization tool, since its specifications required the most work. The most viable future developments will also be discussed in the final part, reflecting to the results of the customer interviews and fault simulations. Especially the requirements for a new automatic fault isolation and restoration feature are reviewed, however thorough specifications including usability and user interface design remain a further development issue.

2. ELECTRICITY DISTRIBUTION BUSINESS IN FINLAND

The electricity distribution business is a natural monopoly in Finland. In 2016, there were 77 Distribution System Operators (DSOs), each operating in a specific geographical area, verified by the Energy Authority. The core activities in electricity distribution business are customer relationship management and asset management, which includes planning, construction and operation of the network. However, today it is common that at least the construction of the network is outsourced to independent contractors. [3], [4, pp. 21-23]

The electricity distribution system forms the basis for electricity distribution business and also the operational environment for the DMS. This chapter provides a quick review of the Finnish electricity distribution system, introducing e.g. the most common voltage-levels, network types and earthing systems.

Due to the nature of the electricity distribution business, the industry is supervised and regulated by the Energy Authority. This regulation strongly affects the actions and needs of the DSOs, and therefore it is necessary to understand the regulation of the electricity distribution business in Finland. The regulation of the electricity distribution business is discussed in the latter part of this chapter.

2.1 The Finnish electricity distribution system

Despite the constant increase in the use of distributed renewable energy (especially wind power), the majority of the electricity used in Finland is still produced in centralized power plants [5], while consumption is widely spread across the country. For this reason, electricity must be transferred over long distances to the end customers. The objective of the Finnish power system is to fulfill this requirement safely, reliably and effectively. [4, p. 11], [6, pp. 54-55]

The Finnish power system consists of the nation-wide transmission grid (400 kV, 220 kV and some 110 kV lines), operated by Fingrid Oyj and several distribution systems, operated by local distribution system operators. The distribution system can be further divided into three parts: high-voltage network (HV) (110 kV and 45 kV), medium-voltage (MV) network (mostly 20 kV but also 10 kV and 6 kV is used) and low-voltage (LV) network (1 kV/0.4 kV). [4, p. 11] In this thesis, the main focus is on the MV-network and therefore it will be discussed more thoroughly in the following chapters.

The Energy Authority in Finland categorizes LV-networks ($U_n \leq 1\ kV$), MV-networks ($1\ kV < U_n < 70\ kV$), and HV-networks ($U_n = 110\ kV$) by nominal voltage U_n in its decree [7]. An overview of the Finnish distribution system, categorized accordingly, is presented in Table 1

Table 1. *Overview of the network lengths and cabling rates in Finland. (adapted from [8])*

Unit	LV	MV	HV	Total
Cable (km)	102 746	27 144	226	130 117
Cable (%)	42	19	3	33
Other (km)	139 242	115 967	6804	262 013
Other (%)	58	81	97	67
Total (km)	241 989	143 111	7030	392 130
Total (%)	62	36	2	100

HV-network (or regional network/sub-transmission network) is the distribution system's connection point to the nation-wide transmission grid. HV-networks are operated by some DSOs or Regional Network Operators (RNOs). As can be seen from Table 1, the HV-network consists mostly of overhead lines, but due to the high reliability requirement, they are usually built tree-safe. For this reason, faults in the HV-network are rare. HV-networks are usually built meshed and may be operated either radially or in a loop, although it is more common to use radial operation [6, p. 57]. HV networks are usually not documented in the DMS and therefore the DMS contains no functions regarding the HV-network. Hence, HV-networks are not discussed further in this thesis.

Primary substations are the interface between HV- and MV-networks. A primary substation traditionally includes at least one primary transformer, HV- and MV-switchgear, auxiliary power system and a Remote Terminal Unit (RTU) for communication to the Network Control Center (NCC). [4] Traditionally rural MV-networks have been built using overhead lines and urban areas using underground cables. During the recent years, the use of underground cables has increased also in rural areas and the cabling rate of the MV-networks has increased significantly. For example, in 2009 the cabling rate of the MV-networks in Finland was 11 % [9], whereas in 2015 the same number was 19 %. This is mostly a result of changes in legislation, regarding reliability of supply [10]. Still in 2012, the cabling rate of the Finnish MV-networks was one of the lowest in Europe, along with Greece and Ireland [11, p. 17]. MV-networks are usually built in a mesh, but operated radially. This results in cost savings due to simplified network calculations and protection. Due to environmental factors (poorly conducting soil), MV-networks in Finland are built either isolated or compensated (resonant-earthed). This reduces the earth fault currents and touch voltages but also complicates earth fault protection and network calculations [4, pp. 176-183].

In terms of network length, most of the distribution system consists of the LV-network, which typically covers over half of the total length of the distribution system. The LV-networks are fed by secondary substations that consist of a distribution transformer and may also include remote- or manually-controlled disconnectors and an RTU for communication to NCC. Each LV-feeder is usually protected by fuses at the secondary substation. The LV-networks in Finland are usually built using aerial bundled cables (AMKA-cables) or underground cables [4, p. 11]. This makes the LV-network less prone to faults, compared to the MV-network. Like MV-networks, LV-networks are usually operated radially, although meshed configuration is sometimes available, especially in urban areas. Unlike the MV-network, the LV-network is earthed and the TN-C-system with a combined protective earth and neutral conductor (PEN) is used. [4, p. 199]

The operational environments of the DSOs are clearly different. Hence, DSOs can be roughly classified into three categories based on the cabling rate of the MV-network; rural, mixed and urban. This division is based on the classifications used in [12, p. 13] and [13]. The division criteria are:

- Rural DSO: cabling rate less than 30 %
- Mixed DSO: cabling rate 30 % or higher but less than 75 %
- Urban DSO: cabling rate 75 % or higher

According to this classification, there were 52 rural DSOs, 20 mixed DSOs and 7 urban DSOs in Finland in 2015. The Energy Authority also uses a similar classification, although the division criteria are somewhat more complex, depending on multiple technical key figures about the network. [14, p. 8] Therefore the previously defined classification is henceforth applied in this thesis when discussing different types of DSOs.

2.2 Regulation

As mentioned before, the electricity distribution business is a natural monopoly and to operate an electrical network, a network permit is required and the operation is continually regulated. The network permits are granted by the Energy Authority that also effectuates the regulation. The Energy Authority is an expert agency operating under the Ministry of Employment and the Economy. The objective of the Energy Authority is to act as an active promoter of the energy market to find sustainable solutions in cooperation with its stakeholders, while being open, impartial, appreciative and fair. [15], [16] The regulation of the electricity distribution business mainly focuses on the DSOs profits and operational effectiveness. [4, pp. 20-21] The Electricity Market Act, which forms the basis for the regulation is briefly introduced in this chapter, along with the regulation model currently in use.

2.2.1 The Electricity Market Act

The regulation is based on the Electricity Market Act which entered into force in 2013. The act is applied for generation, import, export, transmission and sale of electrical energy. From electricity distribution business point of view, the act defines the operation subject to license, considers pricing, construction and operation of the network and sets several obligations to DSOs, regarding e.g. development of the network and reliability of supply. For DSOs business, one of the most important statements are the reliability requirements that were implemented in the law reform in 2013. These requirements are defined in the sixth chapter of the act. [17] Section 51 states that

"2) a failure of the distribution network due to a storm or snow load may not cause an outage longer than 6 hours in a town plan area;

3) a failure of the distribution network due to a storm or snow load may not cause an outage longer than 36 hours outside a town plan area.". [17]

Although there are a few exceptions to these requirements, they have put a significant pressure on DSOs to improve the reliability of their networks. Due to this, there is a transition period, during which the reliability requirements must be gradually fulfilled. DSOs must ensure that these requirements are fulfilled for 50 % of customers by the end of 2019, with the exception of holiday houses. By the end of 2023 the extent should be 75 % and by the end of 2028 all customers, including holiday houses, must fulfill the requirements. [17] It can be interpreted that, after 2028, outages lasting longer than 6 hours in a town plan area or longer than 36 hours elsewhere, are illegal. However, DSOs may request additional time for the aforementioned deadlines for exceptionally weighty reasons. [17]

In addition to the reliability requirements, the act defines standard compensations that the customer is eligible for, when an outage has lasted at least 12 hours for a continuous period of time. These compensations are defined in section 100 of chapter 13. [17] The amount of standard compensation is proportional to the annual network service fee. These amounts are:

- 10 % when the outage time has been at least 12 hours but less than 24 hours
- 25 % when the outage time has been at least 24 hours but less than 72 hours
- 50 % when the outage time has been at least 72 hours but less than 120 hours
- 100 % when the outage time has been at least 120 hours but less than 192 hours
- 150 % when the outage time has been at least 192 hours but less than 288 hours
- 200 % when the outage time exceeds 288 hours

The maximum refund in the form of standard compensations is, however, limited to 2000 € over a calendar year. A customer receiving standard compensation is also not eligible to other fee reductions for the same outage. [17]

2.2.2 Regulation methods

The regulation is based on a four-year regulatory periods, for which a reasonable pricing criteria have been determined in advance. The Energy Authority confirms the regulation methods for a four-year period at a time, during which the methods remain constant. Then the regulation model is usually slightly altered for the following period, based on the experiences from the previous periods. This kind of regulation came into force on January 1, 2005 and currently a fourth regulatory period is underway. The fourth regulatory period began January 1, 2016 and the current regulation methods are valid until the end of 2019. [18, pp. 7-8], [19, pp. 5-7] Summary of the regulation model is presented in Figure 1.

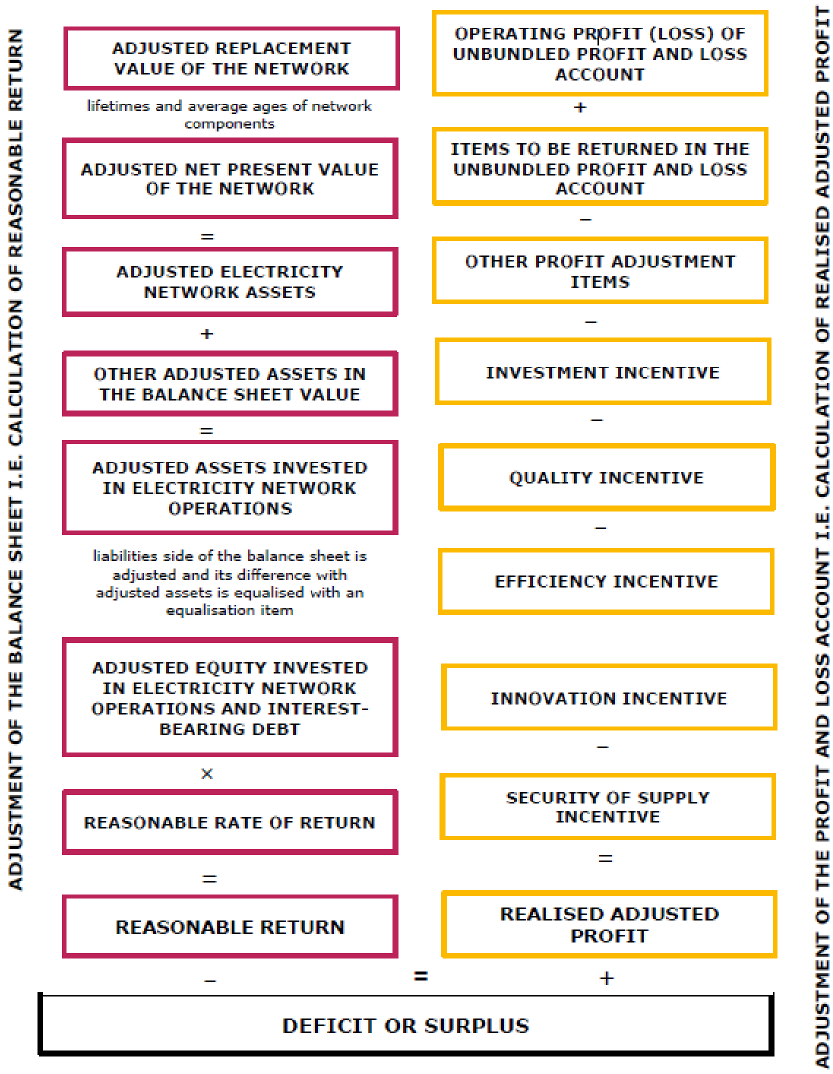

Figure 1. *Summary of the regulation model. [19, p. 6]*

The regulation model presented above is based on calculating the difference between the calculated reasonable return and the realized adjusted profit. If the realized adjusted profit exceeds the reasonable return, the DSO has collected surplus, which must be equalized during the following regulatory period. In practical terms this means that the collected surplus must be either refunded to customers or spent in network development in the following regulatory period. Respectively, if the realized adjusted profit is less than the reasonable return, then the DSO has made a deficit and is allowed to equalize the deficit during the following regulatory period by raising its fees. [19, pp. 20-22]

Both the calculated reasonable return and the realized adjusted profit consist of multiple different factors. Within the scope of this thesis, it is neither reasonable nor relevant to review all the factors implemented in the model. Thorough description of the methods is presented in [19]. However, efficient fault management has a significant effect on the quality incentive, and therefore it is introduced in more detail in the following chapter.

2.2.3 The quality incentive and the regulatory outage costs

The aim of the quality incentive is to create incentive for developing the quality of electricity distribution. Unlike in a competitive market, this kind of incentive is not naturally present in a monopoly and therefore it must be implemented with regulatory methods. The DSO is required to achieve at least the reliability level required by the Electricity Market Act but the quality incentive also encourages for improvements beyond the minimum level. [19, pp. 68-69]

The regulatory outage costs (Keskeytyksestä Aiheutunut Haitta, KAH-costs) form the basis for the quality incentive and hence, are of great interest to the DSOs. The KAH-costs take into account the number and duration of planned and unexpected outages and the number of rapid and delayed auto-reclosings. These incidents are then valued according to the unit prices presented in Table 2. [19, pp. 69-71]

Table 2. *Unit prices of the disadvantage caused by outages. (adapted from [19, p. 71])*

Unexpected outage		**Planned outage**		**Delayed auto-reclosing**	**Rapid auto-reclosing**
$\boldsymbol{h_{E,unexp}}$	$h_{W,unexp}$	$h_{E,plann}$	$h_{W,plann}$	h_{DAR}	h_{RAR}
€ / kWh	€ / kW	€ / kWh	€ / kW	€ / kW	€ / kW
11,0	**1,1**	**6,8**	**0,5**	**1,1**	**0,55**

The unit prices presented in Table 2 are based on a study conducted by Tampere University of Technology and Helsinki University of Technology in 2005 [20]. The DSOs provide the outage information for the Energy Authority, according to the decree [7]. Based on this information, the annual KAH-costs are calculated according to Equation (1).

$$KAH_{t,k} = \begin{pmatrix} KA_{unexp,t} \times h_{E,unexp} + KM_{unexp,t} \times h_{W,unexp} + \\ KA_{plann,t} \times h_{E,plann} + KM_{plann,t} \times h_{W,plann} \quad + \\ DAR_t \times h_{DAR} + RAR_t \times h_{RAR} \end{pmatrix} \times \frac{W_t}{T_t} \times \frac{CPI_k}{CPI_{2005}} \qquad (1)$$

where

$KAH_{t,k}$	=	realized regulatory outage costs in year *t* in value of money for year *k*, [€]
$KA_{unexp,t}$	=	outage period caused by unexpected outages in the medium-voltage distribution network, weighted by annual energies, [hrs]
$KM_{unexp,t}$	=	outage amount caused by unexpected outages in the medium-voltage distribution network, weighted by annual energies, [pcs]
$KA_{plann,t}$	=	outage period caused by planned outages in the medium-voltage distribution network, weighted by annual energies [hrs]
$KM_{plann,t}$	=	outage amount caused by planned outages in the medium-voltage distribution network, [pcs]
DAR_t	=	outage amount caused by delayed auto-reclosings in the medium-voltage network, weighted by annual energies, [pcs]
RAR_t	=	outage amount caused by rapid auto-reclosings in the medium-voltage network, weighted by annual energies, [pcs]
W_t	=	volume of transmitted energy in year *t*, [kWh]
T_t	=	number of hours in year *t,* [hrs]
CPI_k	=	consumer price index of year *k*
CPI_{2005}	=	consumer price index of year *2005*

When calculating the quality incentive, the KAH-costs are compared to the reference level, which is the average of the DSO's annual KAH-costs from the two previous regulatory periods. If the realized regulatory outage costs are higher than the reference level, they increase the realized adjusted profit and therefore decrease the allowed operating profit. Respectively, the allowed operating profit is increased if the realized regulatory outage costs stay below the reference level. The difference of the realized KAH-costs and the reference level is now taken into account in full, when calculating the realized adjusted profit. In the previous regulatory periods, only half of the difference was taken into account, so the effect of KAH-costs is emphasized in the fourth period. However, to make the impact of the quality incentive reasonable, the effect of the incentive is limited by a maximum limit. Therefore the incentive may reduce or increase the DSO's reasonable return for the year in question by a maximum of 15 %. [19, pp. 66-76]

In addition to the quality incentive, the KAH-costs are also taken into account in the efficiency incentive. In the efficiency incentive, they are modelled as an undesirable output when determining the DSO's efficiency from the output/input ratio. The KAH-costs were implemented in the efficiency incentive to prevent "improvement" of efficiency by cutting reliability-related maintenance costs. [19, pp. 76-79], [18, pp. 11-12]

2.3 Reliability indices

In addition to the KAH-costs, international reliability indices are used to indicate the reliability of a distribution system. These indices have originally been developed by the Institute of Electrical and Electronics Engineers (IEEE) in 1998 and they are widely used in the industry. The indices are defined in IEEE Standard 1366. [21], [4, p. 45] The most common indices are:

- *System Average Interruption Duration Index (SAIDI),* which indicates the total outage time for the average customer during a predefined period of time. It is commonly measured in hours or minutes of interruption.
- *System Average Interruption Frequency Index (SAIFI),* which indicates how often the average customer experiences a sustained interruption during a predefined period of time.
- *Customer Average Interruption Duration Index (CAIDI),* which indicates the average length of an interruption experienced by a customer.
- *Momentary Average Interruption Frequency Index (MAIFI),* which indicates how often a customer experiences a momentary interruption during a predefined period of time.

These indices are used for e.g. DSO's internal reporting and planning and comparison of the reliability of different DSOs networks. The same indices are also presented in the annual outage statistics compiled by Finnish Energy, an organization representing companies that produce, acquire, transmit or sell energy. The IEEE Standard 1366 defines also various other indices, but the aforementioned four are the most commonly used ones in Finland.

3. DISTRIBUTION AUTOMATION

Distribution automation comprises a system or a set of devices used to plan, operate, monitor and control the distribution network remotely. [22] Typical distribution automation includes e.g. Intelligent Electronic Devices (IEDs), such as microprocessor based relays, RTUs and IT-systems, such as the DMS. From a system point of view, network automation is crucial, as the exploitability and usability of the DMS and Supervisory Control and Data Acquisition (SCADA) is highly dependent on the available network automation. With higher level of automation in the network, more functions can also be utilized in the DMS. According to the Distribution Automation concept (DA-concept), distribution automation can be divided into company, NCC, substation, network and customer levels [22, p. 401]. This concept is, however, rather old and in this thesis a simplified classification of devices and systems is used. The classification used in this thesis is represented in Figure 2.

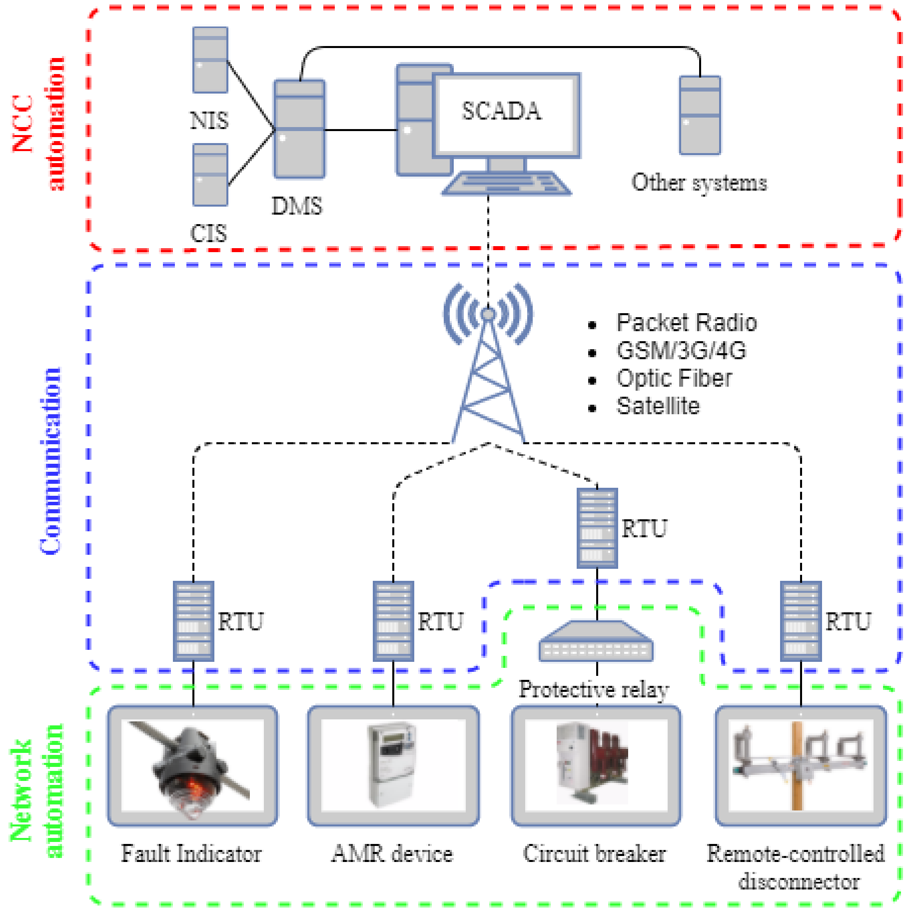

Figure 2. *Different levels of distribution automation.*

The main motives for the use of distribution automation are [22, pp. 401-402]:

- Savings in construction, renovation and maintenance costs
- Better overall control and reliability of the network

NCC automation will be discussed in chapter 3.1, along with the common IT-systems used. In chapter 3.2, the most common network automation devices are introduced, with respect to this thesis. Finally, the interface between the two levels of distribution automation; communication in distribution network is reviewed in chapter 3.3.

3.1 NCC and IT-systems

Network Control Center (NCC) is a location used for centralized monitoring and control of the network. The personnel operating the network in the NCC are called operators. The most common arrangement is to have one centralized NCC for the whole network, but some DSOs have also divided the responsibility of their operating area to multiple NCCs. It is also common to have a secondary NCC in a separate location to ensure control of the network if the primary NCC cannot be used, due to e.g. a fire. Furthermore, DSOs with small operating area may also use a so-called mobile NCC, where the NCC functions are performed from a single notebook computer that is carried along by the operator on duty [4, p. 231]. The NCC is typically responsible for:

- Network state monitoring and control
- Fault management and reporting
- Management of maintenance operations
- Switching planning
- Customer information and support

On top of all, while executing the aforementioned tasks, the NCC is responsible for the electrical safety of the field crews working in the field. [4, p. 231] Especially in fault situations, effective operation of the NCC is of paramount importance. Efficient use and prioritization of resources by the NCC greatly affects the efficiency of the fault management process. Typically all MV-switching operations in the field must be approved by the NCC before they can be carried out. Therefore, if there are a lot of simultaneous faults, it is common that the NCC is congested with incoming calls and becomes a bottleneck in the fault management process. Due to this, it is necessary to have both enough SCADA workstations and competent operators. To ensure sufficient availability of competent personnel in the NCC during major power disruptions, some DSOs have introduced internal training programs to train secondary operators from personnel normally working with other tasks. [23]

To carry out all the aforementioned tasks effectively, the NCC utilizes various IT-systems. The two primary tools for NCC personnel are Supervisory Control and Data

Acquisition (SCADA) and DMS. These systems and their common integration with other systems and information sources is illustrated in Figure 3.

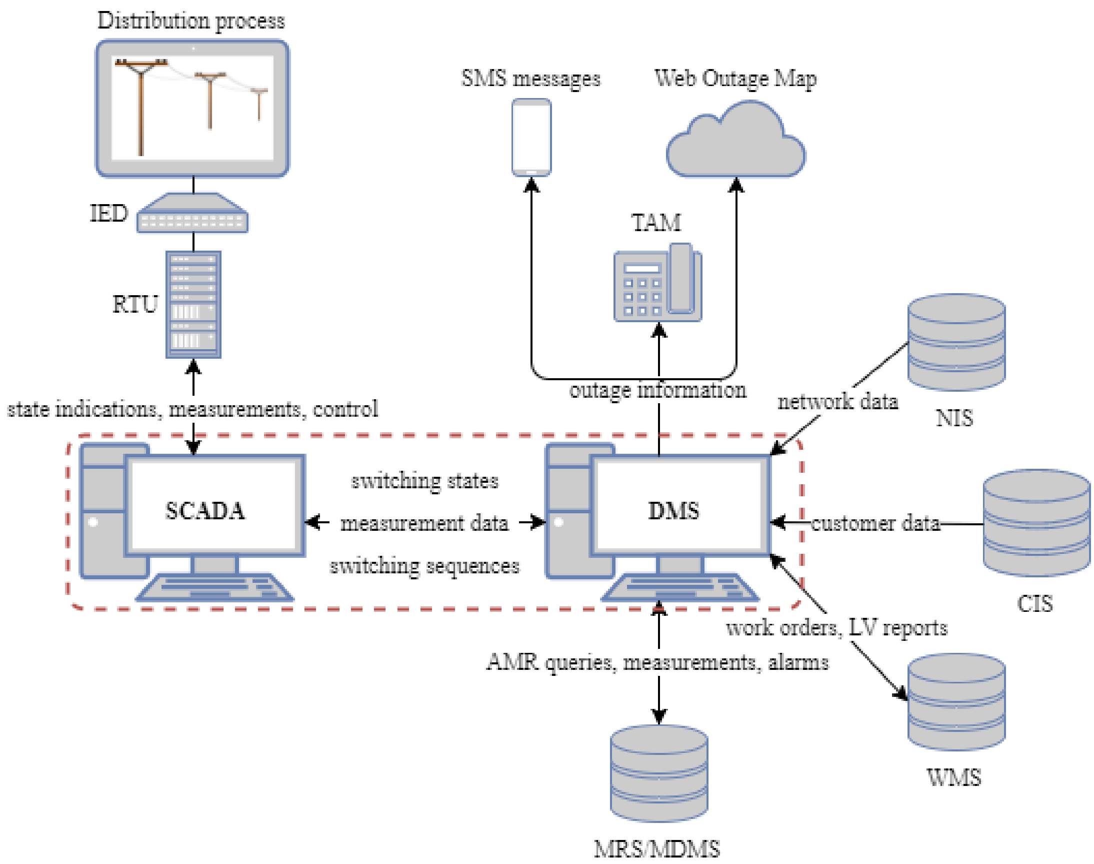

Figure 3. *Primary IT-systems used in the NCC and their integration with other systems.*

These systems are introduced in the following subchapters with a little more detail. The DMS is introduced here only briefly on a general level and the specific product (DMS600) developed by ABB is discussed more thoroughly later in chapter 4.3.3.

3.1.1 Supervisory Control and Data Acquisition

Supervisory Control and Data Acquisition (SCADA) is a system used to directly monitor and control the distribution process in real-time. It gathers and stores information from the distribution process and sends control commands to the devices in the network. The main functions of a SCADA system typically include overview of the distribution process, alarms, remote-control of the switching devices, remote reading of measurements, remote configuration of IEDs and reporting. [4, p. 235]

The requirement for the reliability of the SCADA system is high. Due to this, the power supply for the SCADA system is usually ensured with Uninterruptible Power Source (UPS) system. It is also common to use hot-standby with duplicated process database and SCADA computers. This means, that when a failure occurs on the primary computer, the secondary one takes over the process with little or no interruption. The information in the process database changes rapidly and to maintain real-time awareness of the switching state, the information must be reliable at all times, to all users. Due to this, only the latest information is stored in the process database. [4, pp. 235-236]

As an example of a SCADA system, Figure 4 represents the graphical user interface of ABB's MicroSCADA Pro SYS600. In SCADA, detailed information is usually only available on primary substations and the network is often represented in a schematic view as shown in Figure 4. The typical alarm and event displays are also visible.

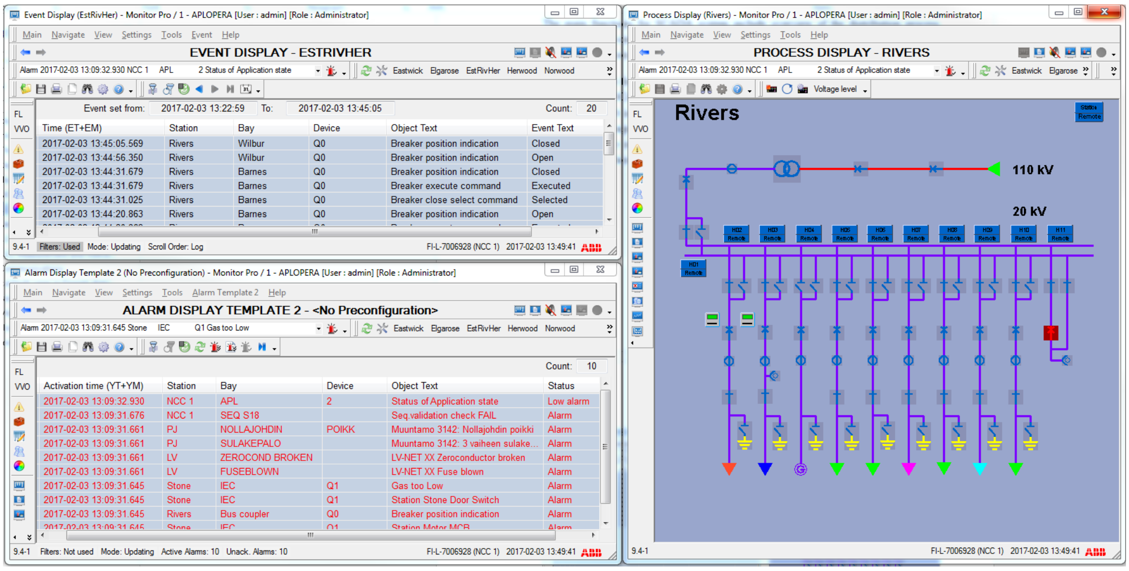

***Figure 4.** User interface of ABB's MicroSCADA Pro SYS600.*

In addition to high reliability, flexible and easy integration between SCADA and other IT-systems is also required as DSOs often acquire their systems from different vendors [24, pp. 64-86]. This integration can be implemented in several ways, using e.g. transfer files, application programming interfaces or middleware. Particularly important is the interface with the DMS. This is usually implemented using OPC (OLE for Process Control) or ELCOM-90 (Electric Utilities Communication) standards or using SCIL-API programming interface, developed by ABB [25, pp. 22-31]. More information on the interfaces between different IT-systems in distribution network operation can be found in [25].

The most widely used SCADA systems in Finland are ABB's MicroSCADA Pro SYS600, Netcon 3000 by Netcontrol Oy and Spectrum Power by Siemens. According to [26] the SCADA systems market was controlled by these three actors in 2005, which mostly applies also today. DSOs tend to make a long-term commitment to the system provider, since switching over to another vendor's system usually requires a lot of work.

3.1.2 Distribution Management System

Distribution Management System (DMS) typically contains a set of functions for real-time network topology management, analysis and inference, operation planning, fault management, customer service and reporting. Unlike SCADA, the DMS does not gather information by itself, but instead utilizes information gathered by several other systems. This information is then used to support the user in e.g. decision-making. A modern DMS typically has interfaces with at least SCADA, Network Information System (NIS), Customer Information System, Meter Reading System (MRS) and Work Management System (WMS). [27, pp. 31-42], [4, pp. 236-244]

On a more detailed level, the network analysis functions usually include power-flow and fault current calculations, which are then used for e.g. protection analysis. Operation planning functions include e.g. tools for switching planning and network switching state optimization. Event analysis, fault location, field crew management, network restoration and reporting are the typical functions for fault management. Furthermore, to provide customers with more accurate information regarding the faulted areas, the customer service function is used. This is usually implemented by integrating the DMS with Short Message Service (SMS), telephone answering machine and web outage map, available on the DSO's web site. [27, pp. 31-42], [4, pp. 236-244]

In the DMS, the network is typically presented on top of a geographical map but schematic views may also be available. Both MV- and LV-networks are usually documented in the DMS and, unlike in SCADA, specific information on network components (e.g. conductor types, transformer rated capacities, installation dates) is also available. The DMS functions mentioned above are introduced more thoroughly in chapter 4.3.3, along with ABB's DMS600 Workstation (WS). In addition to ABB's DMS600 WS, Trimble DMS by Trimble Inc. is also widely used among Finnish DSOs.

3.1.3 Other systems

The SCADA and DMS are the primary tools for the operators in the NCC, but the DSOs typically have several other systems that are also vital for the network operation process. From NCC point of view, these systems are mostly utilized in the background, acting as a basis for the utilization of the DMS, but sometimes they may also be used directly. The most important such systems are the Network Information System (NIS), Customer Information System (CIS), Meter Data Management/Reading System (MDMS/MRS) and Work Management System (WMS). These systems are briefly introduced in this chapter. [4, pp. 236-237], [25, pp. 6-13]

The Network Information System (NIS) contains the network information and also provides functions for e.g. network planning and maintenance. The network information is typically stored in a relational database that contains information on the location of the conductors and components, along with their interconnection and technical specifications. This database is used to provide information for other systems, such as the DMS, and therefore a NIS-DMS –interface is required. Similar systems are also known as AM/FM/GIS (Automated Mapping/Facilities Management/Geographic Information System). [4, pp. 265-268]

The Customer Information System (CIS) is used for customer relationship management. In electricity distribution business, it is used mainly for customer information management, billing and customer service. The customer information stored in the CIS database typically includes e.g. consumer group, energy consumption and billing information. This information is applied in multiple situations in both network operation and planning. For example, customer information can be used in prioritization during fault management process. [25, p. 10]

Meter Data Management System (MDMS) gathers, stores and processes metering data from the AMR devices. It is closely integrated with the *Meter Reading System* (MRS) that comprises of the actual metering devices, data concentrator units and other infrastructure required for remote measurement. The metering data is processed and stored in MDMS database and it can be used e.g. for load forecasting. The DMS also utilizes MRS for LV-network alarms and remote queries. [28, pp. 30-43], [25, pp. 10-12]

Work Management System (WMS) is used for managing e.g. maintenance and construction -related work processes. It provides support for ensuring that all workflows and processes are executed. WMS typically includes functionalities for e.g. work order management and billing. Often reporting functions are also available. If WMS is integrated with DMS, e.g. LV-fault reports filled in through the WMS can be automatically transferred to the DMS. Also in a fault situation, automatic generation of work orders is possible based on the information provided by the DMS.

3.2 Network automation

Network automation can be divided roughly into two categories; control devices and monitoring devices. [29, p. 1] Control devices are the actuators that perform the mechanical opening and closing operations. The control devices used in Finnish distribution networks consist mainly of sectionalizing circuit breakers and remote-controlled disconnectors. Monitoring devices monitor the state of the network and measure and gather information from the network. Typical monitoring devices include e.g. protective relays, fault indicators and AMR devices. These most common network automation devices will be introduced in the corresponding subchapters and also their relation to fault management in the DMS will be considered.

3.2.1 Control devices

Traditionally, the majority of control devices in the network are manual operated disconnectors. These devices have to be operated on-site, and therefore performing switchings can be time-consuming. *Remote-controlled disconnectors (RCD)* are similar devices, but are equipped with a motor and an RTU to enable remote-control via SCADA. With RCDs the operation time can usually be reduced e.g. from 30 minutes to 1-2 minutes, depending on the location and readiness of the field crew. [4, p. 151] In addition to fault-isolation purposes, they are also suitable for reliable isolation during maintenance work, however remote-control must be disabled and the device securely locked. RCDs are usually pole mounted or located inside a secondary substation. The auxiliary power is supplied from the distribution network through an auxiliary transformer and the device is equipped with a UPS system to enable operation when the network is not energized. During long outages, when the batteries of the UPS system have depleted or when the communication to SCADA is not working, the disconnector can be operated manually on-site. RCDs are the most common devices for controlling the MV-network remotely and sufficient amount of these devices must be installed in the network to enable the use of advanced functions in the DMS.

A *sectionalizing circuit breaker (SCB)* is a remote-controllable switching device, equipped with a protective relay, much like the ones located at the primary substation. SCBs are usually pole mounted and mainly used in overhead line networks, although solutions for cabled networks are also available [30]. Comparing to RCDs, the advantage with SCBs is that customers located before the faulted section do not experience an outage. SCB is designed to be capable of breaking even the highest fault currents, but it cannot be used to reliably isolate a line section for e.g. maintenance work. It may also include functions for rapid and delayed auto-reclosings (RAR/DAR).

3.2.2 Monitoring devices

The aforementioned remote-controlled switching devices are essential to remotely control the network and utilize, e.g. automatic restoration functions in the DMS. In addition, devices for fault detection, measurements and location are needed for accurate determination of the fault location.

Modern *protective relays* used in MV-networks are microprocessor-based IEDs, containing functions for at least short circuit protection, earth fault protection and auto-reclosings. In addition, functions for e.g. power quality assessment, fault location and disturbance recordings are also often available. [31], [32] The relays are located in the primary substation but can be configured remotely from the NCC via SCADA or with a specific configuration software, provided by the manufacturer. From DMS point of view, it is important that the relays in the substation are capable of reliably measuring fault impedances and currents and transmitting the information to the DMS, as this information is used as a basis for the fault location function in the DMS. Overall, the basic requirements for protective relays are reliable, selective and fast operation [6, pp. 342-343].

Fault indicators are devices designed to detect and indicate faults in the network. Short-circuit detection is usually based on detecting the overcurrent generated by a short-circuit, but for earth fault detection the used methods vary depending on the grounding of the network. In high impedance networks (unearthed or compensated) the detection can be based on e.g. measuring changes in the zero sequence current [33, pp. 41-45] or monitoring the polarity of the zero sequence current and voltage [34]. The indication method can be either visual or remote. Visual indications can only be detected on-site but with remote indication, the information is available in the DMS and/or SCADA. Figure 5 represents the principle of fault indicator operation and implementation.

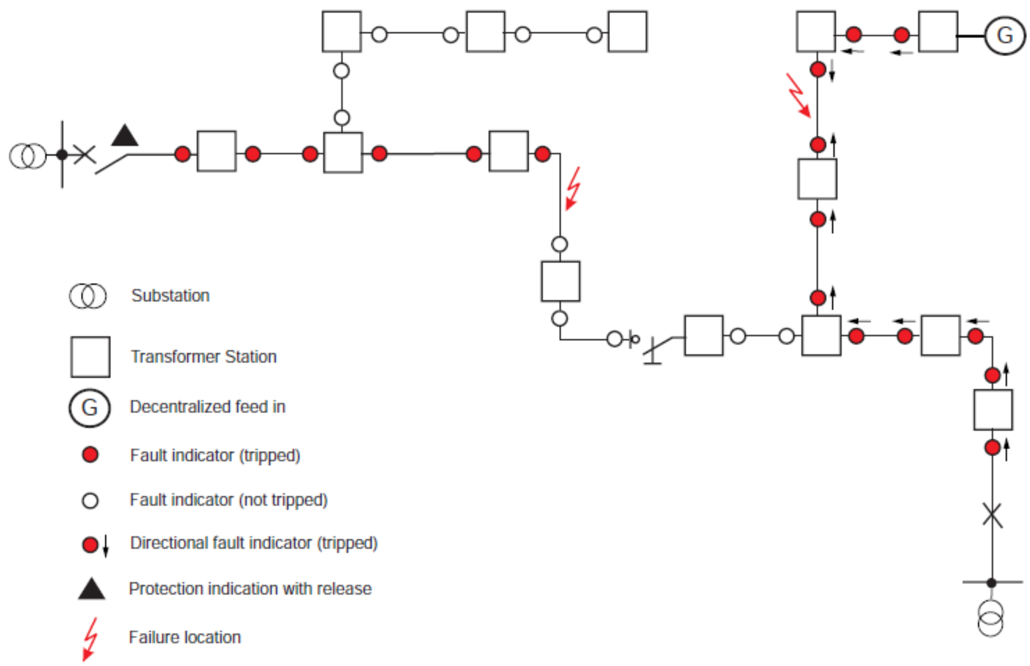

Figure 5. *Principle of fault indicator operation and implementation [35, p. 5]****.***

So far, fault indicators are not widely used in Finnish distribution networks, although there have been some pilot projects by a few DSOs. [36], [37] Also, according to [37, pp. 60-69], there has been some problems regarding the reliability of the indicators installed. With reliable indication information, the fault location and isolation process could be expedited significantly, especially in cabled networks where the fault location is usually not clearly visible.

AMR meters are often the only automation devices available in the LV-network. They are mainly used for remote reading of the hourly energy consumption data. However, the devices often also include functions that can be utilized in fault management. Typical functions useful for fault management include alarms for unsupplied customer, loss of phases (blown fuses), voltage unbalance and zero sequence faults. The alarms can be either spontaneous or the information can be gathered with a query from the DMS. The meters also provides customer-specific outage data for e.g. customer service and reporting purposes. Implementation of the AMR system has notably changed the LV-fault management process. Traditionally the DSO has received information about an LV-outage from an unsupplied customer via phone but now the AMR system enables almost immediate detection of LV-faults. The aforementioned queries can also be utilized in locating the fault, and with a suitable algorithm, the meters can also detect broken conductors in the MV-network, which are often not detected by the relays in the primary substation. Although AMR meters have been categorized as monitoring devices in this thesis, some solutions may also include control features, enabling e.g. automatic isolation in case of a zero sequence fault. In some cases, the control features may also be used remotely from the NCC to e.g. switch off the electricity supply due to overdue electricity bills. [4, pp. 258-259]

3.3 Communication in distribution network

With increasing amount of automation, the distribution network has become more and more dependent on communications. However, the importance of the communication links vary. For example the reliability requirement for primary substation communication is considerably higher than that of the AMR measurements. Furthermore, the capacity, security and cost-efficiency of the technology must be taken into consideration. For these reasons, multiple different communication technologies are utilized in distribution networks. To enable interconnection of different devices from different vendors, a set of common rules is also needed. These rules are called protocols and they govern the format of messages, the generation of checking information, the flow control and the actions to be taken in the event of errors. [38, p. 461] The most common communication technologies and protocols will be reviewed in this chapter, focusing especially on the ones used in Finnish distribution networks.

The communication technologies used in Finnish distribution networks consist mainly of the following:

- Cable (optical fiber or copper)
- Mobile network (2G, 3G, 4G)
- Radio link
- Satellite
- Power-Line Carrier (PLC)

Fixed cable links are usually applied in primary substation communication due to their high reliability and capacity. Optical fiber is also immune to electrical disturbances. The installation of fixed cable links is, however often expensive, especially with long-range communications.

Traditionally DSOs, the large ones in particular, have operated their own radio link networks to facilitate the communications in the distribution network. [39, pp. 404-411] Today some DSOs have noted, that the radio link network is not necessarily capable of fulfilling the requirements for communication in smart grids. With the development of the public mobile networks an alternative approach for communication solution has come up. For example the second-largest Finnish DSO Elenia uses IP-based communication over public mobile networks in primary substation communication with satellite backup connection. [40], [41] Utilizing 3^{rd} (UMTS, HSPA) and 4^{th} (LTE, WiMAX) generation mobile telecommunication technologies, high performance can be achieved cost-efficiently. Currently, the public mobile networks can reach data rates of over 100 Mbit/s, although the rates vary considerably across the country. [42] Mobile networks are also used for less vital communications such as AMR measurements and remote-controlling of disconnectors. For these purposes, the GSM and GPRS technologies are sufficient, albeit they may become congested if hundreds of messages are being sent simultaneously via the same base station. [39, pp. 409-410] Today the public mobile networks and electricity distribution networks have become highly interdependent. The mobile network base stations are dependent on the supply electricity and during long outages, the mobile network may not be available in the outage areas. Meanwhile, the distribution networks require the availability of the mobile network to maintain control of the distribution network in fault situations (e.g. isolations with remote-controlled disconnectors).

Satellite connections are rare and often slow, e.g. in the case of Elenia the data rate is 40 kB/s. [41] Therefore they are more suitable to be used as a backup-connection. Power-Line Carrier (PLC) is a technology where the electrical conductors are utilized as a transmission medium. In PLC the transmitted signal is modulated into the power wave, using high frequency. PLC has been used especially in remote reading and setting of AMR meters, however the data rates in PLC are very low (few kbits/s at most). For this reason, it is more efficient to use PLC in LV-networks to transfer data from the AMR meters to secondary substations, where a hub/concentrator unit forwards the information via, e.g. GPRS. [4, pp. 245-247]

In addition to the physical mediums and technologies used to transmit information, common rules, i.e. protocols are needed to ensure mutual understanding of different devices and systems. Different protocols exist for e.g. communication between the IEDs inside a primary substation and communication between a primary substation and the NCC. Along with international standard protocols, released by the International Electrotechnical Commission (IEC), multiple de facto standards and proprietary protocols are also used in the industry. The most common communication protocols used in Finland will be reviewed in the following. Illustration of the commonly used protocols, along with communication technologies is presented in Figure 6.

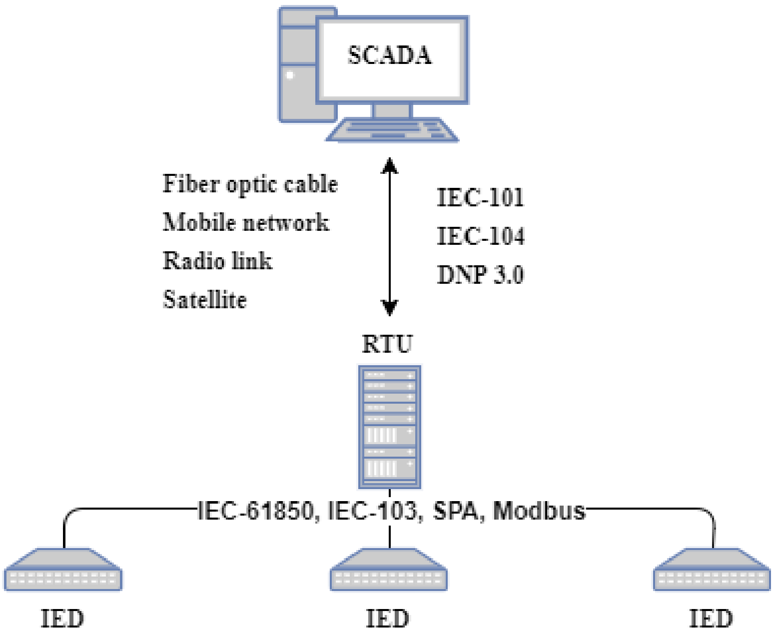

Figure 6. *Illustration of common communication technologies and protocols.*

For primary substation communication, IEC 61850 is the latest commonly used protocol. It defines a complete data model and introduces an XML-based language for vendor-independent method of describing devices and their configurations. It also introduces Generic Object Oriented Substation Event (GOOSE) messages that enable direct communication between different devices via IEC 61850 station bus. This, for instance, reduces the amount of wiring required (better flexibility and expandability) and improves the protection coordination. Overall, the IEC 61850 improves the interoperability of different devices from different vendors and facilitates more efficient device integration, which results in better cost-efficiency. [43], [44] A comprehensive study regarding IEC 61850 can be found in [45]. Besides IEC 61850, protocols used for primary substation communication include e.g. IEC-60870-5-103 (often abbreviated as IEC-103), SPA-bus developed by ABB and Modbus, developed by Modicon. [46] These protocols are however rather old and are phasing out as the DSOs are switching over to the newer IEC 61850.

IEC 60870-5-101 (IEC-101), along with its expansion IEC 60870-5-104 (IEC-104) are the most widely used protocols for communication between the substation RTU and the SCADA system. They are both companion standards of the IEC 60870-5 standard set for telecontrol and communication in distribution automation. IEC-101 is a rather old standard, released in the beginning of the 1990s, but is still widely used today. It defines an interoperability list that is used to ensure interoperability between devices of different vendors. In the list, applicable functions for devices are marked by vendors and common denominator between different vendors can be used to find the possible function range. IEC-101 is designed for serial communication with relatively slow transmission media (9600 bit/s to 64000 bit/s, depending on the interface). [47] IEC-104 is an extension of the IEC-101, which facilitates the use of standard TCP/IP network in communication between the NCC and the primary substation. This enables simultaneous data transmission between multiple devices. [48] Another commonly used protocol is the DNP 3.0 (Distributed Network Protocol). It is closely related to IEC-101 but provides some additional features that make it somewhat superior, compared to IEC-101. One of these features is the ability to run TCP/IP based communication, much like with IEC-104. [49]

4. FAULTS AND FAULT MANAGEMENT IN GENERAL

The standard SFS-EN-50160:2010 defines an outage as a condition in which the voltage at the supply terminals is less than 5 % of the reference voltage. The outages can be classified into planned outages and unexpected outages. In a planned outage, the customer is notified in advance whereas an unexpected outage is caused by a permanent or transient fault, mostly related to external events, equipment failures or interference. The unexpected outages can be further classified as: [50, p. 14]

- a short outage, when the outage duration is 3 minutes or less
- a long outage, when the outage duration exceeds 3 minutes

Majority of the unexpected outages are short, (e.g. around 90 % in a network consisting mostly of overhead lines) and are typically cleared by the auto-reclosing operations (RAR/DAR). [4, pp. 79-80] In cabled networks, however, the outages are usually caused by permanent faults and therefore auto-reclosings are typically not used. Long outages are less common, but require reparative actions, since they are caused by permanent faults. In this chapter, the basic fault types and sources are reviewed along with major power disruption situations and their effects in both rural and urban networks. Also, the general fault management process and its progress is discussed in the final subchapters.

4.1 Fault types and causes

There are two basic types of faults that commonly occur in the distribution network; short-circuits and earth faults. In the MV-network, however, they are clearly different by nature and therefore require e.g. different kind of protection solutions and location techniques. In the LV-networks, fault protection is fairly straightforward and a simple overcurrent protection is sufficient with fuses being the most common protective device. With short-circuits, the case is also similar in the MV-network, but due to the earthing systems used in the MV-network, the behavior of the network during an earth fault is clearly different than during a short-circuit. For this reason, a different kind of solution for earth fault protection is required. A clear majority of the outages experienced by customers are caused by a fault in the MV-network, possibly over 90 % according to [4, p. 125]. Hence, this chapter discusses the two fault types mainly in MV-network context.

4.1.1 Short-circuit faults

Short-circuit faults occur when two or more line conductors are connected through an unintended path with very low impedance. Typical causes for a short-circuit are e.g. breakdown of insulation or a fallen tree branch that connects two phase conductors together (overhead networks). The two most common types of short-circuit faults are two- and three-phase short-circuits. The currents in both situations are typically higher than load currents. For example, a typical three-phase short-circuit current in the busbar of a primary substation is 5-12 kA and often 500-2000 A in the network. Therefore, an overcurrent protection can be utilized for short-circuit faults. Due to the high magnitudes of three-phase short-circuit currents, the detection is usually fairly simple. However, low-impedance three-phase short-circuits occurring near the primary substation often cause significant voltage dips for all customers fed by the same primary transformer and therefore require rapid clearing. The highest three-phase short-circuit currents in the network are often interesting to ensure the withstand capability of the conductors during a fault. Besides the basic two- and three-phase short-circuits, there is also a special case, a so called earth short-circuit. In this case there is also a conductive connection to earth while two or three phase conductors are short-circuited. [4, pp. 28-33]

The magnitude of the fault current in a two-phase short-circuit is usually lower, approximately 87 % of the corresponding three-phase short-circuit current. Therefore the two-phase short-circuit currents at the end of long feeders are often of particular interest to ensure the correct operation of the feeder protection in all situations. Sometimes when the feeder load current is high and the two-phase short-circuit current is low (e.g. 150-200 A), selective and reliable configuration of the feeder protection may be troublesome and network reinforcements may be needed. [4, pp. 29-30]

The modelling of three-phase short-circuits is quite simple, as they are symmetrical by nature. However, with two-phase short-circuits, the situation is different and therefore symmetrical components must be used. This modelling is used in the DMS for a variety of functions, e.g. fault current calculations for protection analysis and constraint checking and determination of the fault location based on the measured fault current. The modelling theory will not be discussed further in this thesis. Further information is available at e.g. [4] and [6]. The DMS and its functions will be introduced in more detail in chapter 4.3.3.

4.1.2 Earth faults

The most common fault type in the distribution network is the earth fault. According to [51, p. 2] even 70 % of the unexpected outages may be caused by an earth fault. An earth fault occurs when a phase conductor is connected to earth or to a component that is directly connected to earth, through a very low impedance. A typical cause for an earth fault is a fallen tree that forms a connection between the earth and a line conductor. Earth faults may generate potentially dangerous touch and step voltages. To reduce these voltages to a safe level, either the earth resistance or the earth fault current must be reduced. Due to poorly conduction soil in Finland, heavy earthings would be needed to reduce the earth resistance sufficiently, which would be very costly. For this reason, the earth fault current is reduced by building the MV-networks as isolated, which means that no earthing is used at all, or resonant-earthed (i.e. compensated) by earthing the network through an inductive reactance. This in turn complicates the detection and analysis of earth faults. In addition to the single-phase earth fault, it is also possible to have two different phase conductors connected to earth simultaneously in different locations. These conductors are then short-circuited through the earth. This is called a cross-country fault. [4, pp. 176-183]

The earth fault current is typically very low in both isolated and compensated networks. Particularly in overhead feeders, the current is often less than 10 A, which is clearly lower than the typical load current and therefore rules out traditional overcurrent protection. Instead, methods based on measuring the zero sequence current and voltage and the phase angle between them must be introduced. Especially troublesome are the high-impedance earth faults which are not often detected by traditional feeder protection. A conductor break with the feeding end not touching the ground is an example of a very high-impedance earth fault. These faults have traditionally been impossible to detect, but some AMR meters now provide the ability to detect the MV-conductor breaks from the LV-side. [4, pp. 190-198] Unlike with short-circuit faults, calculation of the fault location during an earth fault is practically not possible in compensated networks since no device is usually capable of reliably measuring the required fault impedances for the calculation. The recent extensive cabling of feeders has increased the earth fault currents and power losses, forcing the DSOs to add compensation coils to their networks. [52] Hence, the compensated networks are becoming increasingly common and for the moment, generally the only way to locate earth faults without fault indicators is by utilizing experimental switchings. Experimental switching methods are discussed further in chapter 4.3.1.

4.1.3 Sources of faults

As previously discussed in chapter 2.1, there are different types of DSOs, based on the type of network they are operating and therefore at least somewhat different challenges are faced by different types of DSOs. While the clear majority of the faults occurred in a rural DSO’s network are caused by natural phenomena like wind or snow, in an urban DSO’s network faults are more commonly caused by actions of outsiders or defects in design. This is illustrated in Figure 7, where the average interruption durations for customers in different types of networks are visualized for the year 2014. In this figure, “natural phenomena” comprise factors like wind, snow, ice, thunder and wildlife and “technical causes” are defects in design or misoperations by DSO. The “other causes” include e.g. planned outages and the actions of outsiders.

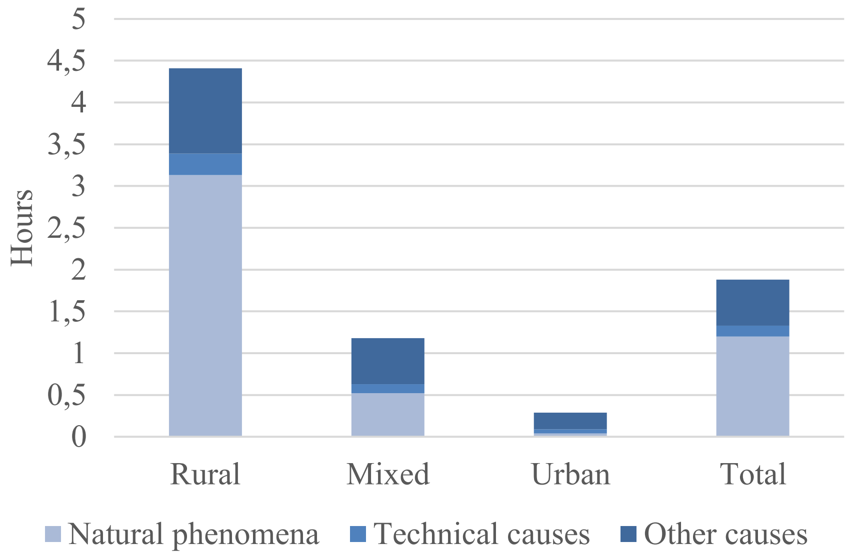

Figure 7. *The average interruption durations for a customer (SAIDI) in different types of networks in 2014. (adapted from [53])*

As can be seen, natural phenomena accounts for a clear majority of the annual outage time in rural areas but is somewhat marginal factor in urban areas. Faults in total are also significantly less common in urban areas. Therefore urban DSOs’ requirements and preferences regarding fault management are often somewhat different from those of rural DSOs’ and also the importance of fault management in general is lower.

4.2 Major power disruptions

Major power disruption refers to a severe fault situation where a significant number of customers in a certain area are experiencing an outage simultaneously for a considerable period of time. In the literature, there are various different terms describing this kind of situation. The IEEE uses the terms “Major Event” and “Major Event Day” [21, p. 19]. The terms “major outage” and “major blackout” are also used in international literature when referring to a similar situation. In the Finnish literature, the term “major disturbance” is commonly used in theses and reports (e.g. [54], [55], [56]). With this term, however, it should also be specified what is the subject of the disturbance, since based on a quick Google search, the same term is used internationally for all kinds of disturbances. The term “major power disruption” specifies the subject and has been used in both international and Finnish literature (e.g. [57], [23]) and is therefore used henceforth in this thesis. In addition, “major power disruption” may also refer to a failure of the nation-wide transmission grid that causes extensive outages throughout the country. In this thesis, however, only the outages originating from faults in the distribution network will be considered and the term "major power disruption" refers to an extensive outage situation in the distribution network level.

There is no one clear definition for a major power disruption. The IEEE defines a Major Event as "an event that exceeds reasonable design and/or operational limits of the electric power system" [21, p. 19]. A Major Event also includes at least one Major Event Day (MED). MED is a day during which the daily SAIDI exceeds a certain threshold value that is calculated from historical daily SAIDI data [21, pp. 34-40]. In a collaborative report by Tampere University of Technology and Lappeenranta University of Technology, a major power disruption is defined as a situation where over 20 % of the customers of a DSO are unsupplied or where a 110 kV transmission line, 110/20 kV primary substation or a primary transformer is faulted for several hours. [58, p. 40] In addition, severity ratings for different major power disruptions are introduced in [59, pp. 71-90], based on the probability, extent and duration of the situation. DSOs often also have their own criteria for a major power disruption, which may be based on e.g. the percentage of unsupplied customers, amount of simultaneous faults or the importance of unsupplied customers. These criteria may be used in fault management to evaluate the situation in real-time. DSOs may, for example, have a distinct organizational setup for handling major power disruptions that is activated based on some evaluation criteria. [23] These criteria are discussed further in chapter 7. Major power disruptions as a phenomena are somewhat different in different types of networks and hence will be discussed separately in the following chapters.

4.2.1 Causes and effects in a rural DSO's network

In a rural area, major power disruptions almost always originate from severe weather conditions. Hence, it is typical that there are a lot of faults spread across a wide geographical area and outages can be expected in the operational areas of several DSOs. Therefore all available resources are usually activated to cope with the situation and even so resources must be prioritized, especially in the early stages of the disruption. In addition, since it is common that several DSOs in a certain area are affected by the disruption, it may be difficult to e.g. lend resources (personnel and equipment) from the neighboring DSOs or their subcontractors.

Typically the outages experienced during a major power disruption last long, even several days for some customers. The situation is particularly challenging if the disruption occurs during the winter. With temperatures well below the freezing point during prolonged outages, there is a considerable risk of damages to property and even to human health. It is also common that some mobile network base stations go down, causing the mobile network to go out of service in certain areas. This, in turn, causes insecurity and complicates the fault management process. Even during the summer, some home care patients are at risk and significant hindrance is caused to everyone affected by the outage. [60, p. 13]

Apart from the customers living in the rural area, there are usually several local municipality centers located in the operational areas of rural DSOs. It is possible that some of them become completely unsupplied during a major power disruption. In such case, the private and public services are interrupted. This includes e.g. shops, banks, healthcare centers and schools. The water supply is also partly dependent on electricity and therefore it may also be interrupted. Although the outages in a municipality center are usually not as long as in the rural areas, there have been cases where prolonged outages have forced the authorities to consider even partial evacuations. [60, pp. 13-14], [61], [62]

As an example, the Tapani-Hannu-storm that occurred on consecutive days after Christmas in 2011 caused outages for over 500 000 people and has arguably had significant overall impacts on the society and the energy industry. This major power disruption resulted in immense media attention and public concern about the reliability of electricity supply in Finland, which eventually led to the previously described changes in legislation. In a research conducted by the Prime Minister's Office in 2017 [63], an assessment was made to project the effects of a similar storm for the year 2016 in a mostly rural area. The projection is presented below in Figure 8. The figure also represents the effects for the year 2011, which is used as a reference.

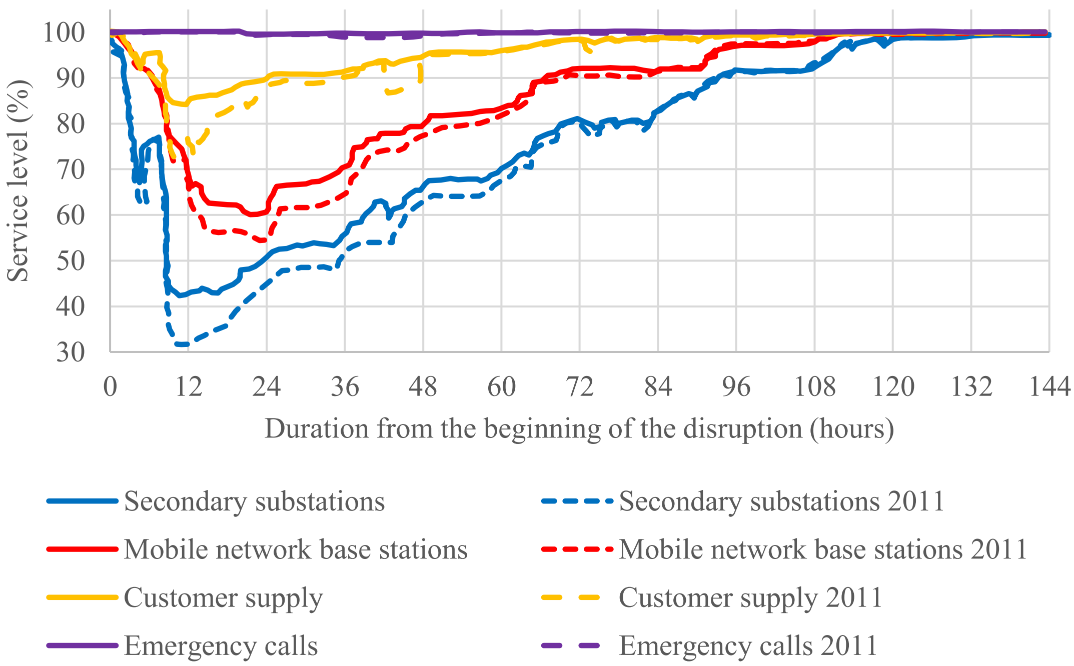

Figure 8. *Projected effects of a major power disruption in the studied network for years 2016 and 2011. (adapted from [63, p. 83])*

As can be seen from the figure, e.g. the amount of operational secondary substations during the worst phase of the situation would still be less than 50 % in 2016. Hence it is clear, that despite the DSOs' efforts to improve the reliability of their networks, a storm similar to the Tapani-Hannu would still have significant effects.

4.2.2 Causes and effects in an urban DSO's network

As mentioned earlier, weather conditions are usually not the most common source of major power disruptions in urban DSOs' networks. Instead, human errors or defects in design are the more likely causes. [64], [65] In an urban area, the outages are typically considerably shorter and rarer than in rural areas. It is typical that the whole situation originates from a single fault in the network, which causes an outage for thousands of customers. Therefore, for example, prioritization is not usually a key issue as sufficient resources are usually available unlike in the case of a rural DSO. However, locating and repairing the fault may take some time, since the networks in urban areas often consist mostly of underground cables.

In an urban area, even a shorter outage situation can be classified as a major power disruption as it often has significant effects on businesses, industry and public services. For example public transportation and the operation of corporate headquarters and government agencies may be interrupted. [60, pp. 12-14] Moreover, faults and especially major power disruptions are so uncommon in urban networks that the personnel may lack the routine to cope with the situation. Hence, the requirements and preferences for fault management are likely to differ from those of rural DSOs'. Overall, fault management is often considered a lower priority by urban DSOs than rural DSOs. Due to this, fault management is mostly discussed from a rural DSO's perspective in this thesis.

4.3 The progress of a general fault management process

Fault management is a key part of the network operation process. The other main functions of the network operation process include network state monitoring and control, operation planning and execution of planned maintenance operations. [4, pp. 231-232] Typically, the NCC is responsible for carrying out most, if not all, of these tasks. The general fault management process is depicted below in Figure 9. [66, pp. 31-33]

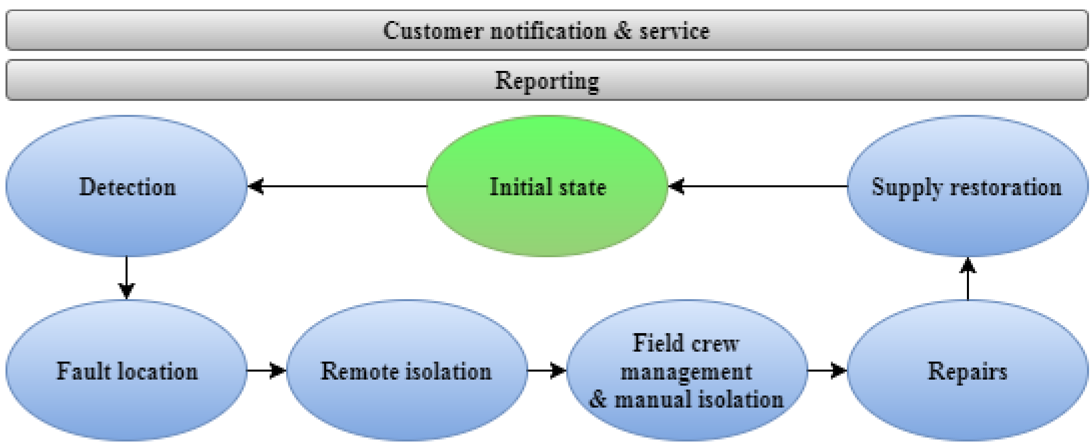

Figure 9. *The general fault management process.*

While most of the phases depicted in Figure 9 apply for both MV- and LV-fault management, the process is somewhat different for MV- and LV-faults. Therefore the general progress of the processes will be discussed separately in the two following chapters.

4.3.1 MV-faults

Since MV-faults usually cause an outage for a greater amount of customers compared to LV-faults, MV-fault management is normally prioritized over LV-fault management. The process is typically initiated when a protective relay trips a circuit breaker after detecting a fault and the operator is alarmed via SCADA. However, high impedance earth faults may not be detected by the relay protection and in such cases the process is initiated only after the NCC is informed about the fault via e.g. customer calls. After possible auto-reclosings, the operator acknowledges the fault and analyses the situation based on the information available from the IT-systems and his/her experience. If fault location information is available via e.g. DMS, it is utilized in the fault isolation process. Experienced operator can also often make an educated guess of the possible fault location, based on his/her knowledge. With a reliable and precise fault location information, the fault isolation process is straightforward and can be performed swiftly. However, the fault location is often unknown and the operator has to carry out experimental switchings, first using the RCDs available and then guiding the field crews to operate the manual disconnectors. Experimental switching is a method to locate the faulty zone by opening disconnectors along the feeder and then closing the circuit breaker to see if it trips or not. Using this method, the faulty zone is eventually located. Two experimental switching procedures are commonly used; the zone by zone rolling and the bisection method. [66, pp. 37-43]

In *zone by zone rolling* method, all the RCDs along the feeder that border the remote-controlled zones are opened. The operator then proceeds by energizing the zones one by one, starting from the beginning of the feeder, until the feeding circuit breaker trips. To reduce the amount of customers affected by the eventually tripping circuit breaker, confirmed healthy parts of the network may be transferred to another feeder. When using the zone by zone rolling method, it is necessary to ensure the making capacity of the disconnectors used, since they might be closed under fault. The advantage of this method is that the feeding circuit breaker trips only once, reducing the amount of short outages experienced by customers and the stress caused to the network by the short-circuit current. However, there is also a downside as this method is slow, especially in feeders with a lot of RCDs and in networks with slow field communications. For this reason, the isolation process is commonly started with the *bisection method* and then the zone by zone rolling is used. In the bisection method, the operator chooses an RCD located somewhere in the middle part of the unsupplied feeder and divides it roughly in half. The circuit breaker is then closed and if the breaker stays closed, the faulted zone is located downstream from the opened RCD. The faulted zone is usually confirmed by closing the bordering RCD and checking if the circuit breaker trips, ensuring that the fault is indeed located in the suspected zone. Otherwise the fault is located upstream from the opened RCD and supply can be restored to the downstream network via adjacent feeders, if available. This operation may be performed a few times and then the isolation process is continued with the zone by zone rolling. Compared to the zone by zone rolling, bisection method is faster but often causes multiple short outages to customers. Additional stress is also caused by the short-circuit current that flows through the network multiple times, which may result in a conductor break if the conductors are not allowed to cool down between the switchings. Hence, a combination of both methods is often used. [67, pp. 51-53], [66, pp. 39-43]

After the faulty section has been isolated remotely, the operator dispatches a field crew to continue the isolation with the manual disconnectors. Although both of the previously described methods can be utilized also in the manual isolation process, usually the bisection method is used in practice, since zone by zone rolling would be too slow. [67, p. 53] After the fault has been isolated, the field crew repairs the fault and restores the supply for the rest of the customers. Finally, the operator is responsible for restoring the network to the normal switching state and reporting the fault The DMS is typically an essential tool in fault reporting, especially for larger DSOs.

An example of the progress of an actual MV-fault management process from the aspect of unsupplied customers and power during the process is presented below in Figure 10.

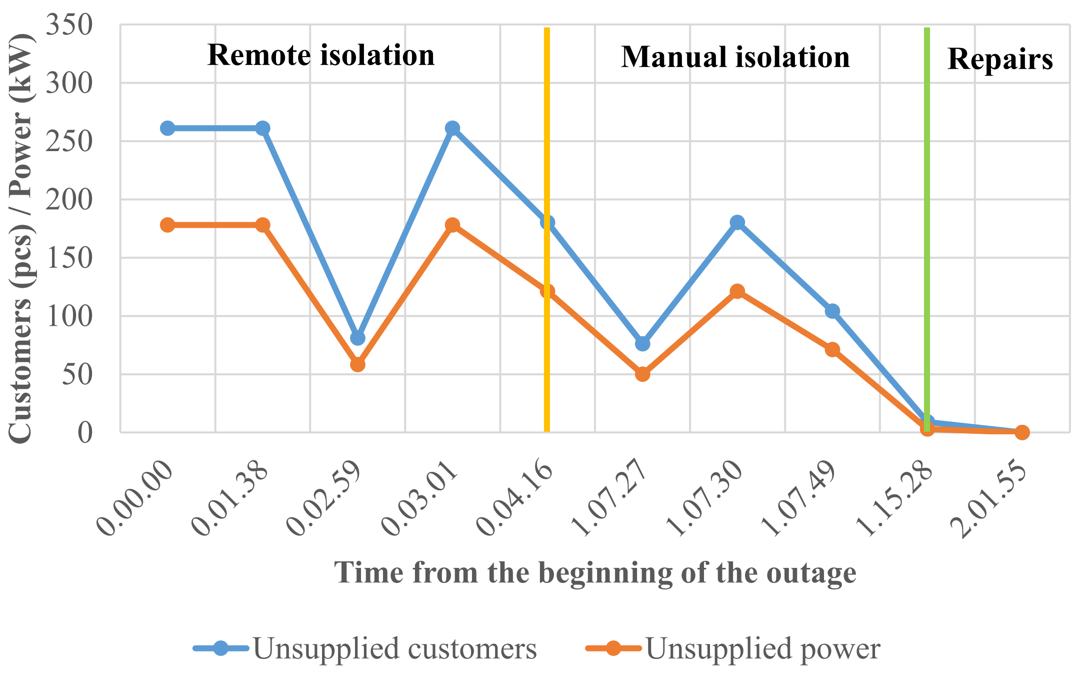

Figure 10. *Unsupplied customers and power as a function of time during an actual MV-fault management process.*

Figure 10 represents an actual MV-fault management process during a fault situation in a rural DSO's network. Different phases of the process are also illustrated in the figure.

In addition to the restoration operations, customer notification can be seen as an additional part of the fault management process. In section 59 of chapter 6, the Electricity Market Act obliges DSOs to promptly inform their customers about ongoing faults and also an estimation of the fault duration has to be given. [17] Therefore the operator has to update the estimated durations to the IT-systems (often DMS) during the fault management process, which are then provided for customers, utilizing e.g. web outage maps and SMS messages.

4.3.2 LV-faults

Due to a more limited geographical extent and lower level of automation in LV-networks, the fault management process for LV-faults is somewhat different than for MV-faults. Although most of the phases depicted in Figure 9 are also present in LV-fault management, they are handled by different actors.

Traditionally there have been no remote indication of faults in the LV-network and the fault management process was almost always initiated by a disturbance call from a customer experiencing an outage or appliance failures. This has changed in the recent years, since the government decree on reporting and measuring electricity delivery [68] defined that, by the end of 2013, at least 80 % of the consumption sites must be equipped with an AMR device. Today many DSOs receive spontaneous alarms from AMR devices and the LV-faults can be repaired even before the customer notices anything.

Today, the operators typically send remote queries to the AMR devices in the presumably faulted LV-network via e.g. DMS to determine whether there is actually a fault in the LV-network or if the fault is in customer's own systems. After the LV-network has been determined faulty, a field crew is dispatched to handle the repairs. The LV-fault management does not require significant effort from the operator, since the field crews may perform LV-switching operations on their own and there is no need to instruct the field crews as was the case with MV-faults. Additionally, the fault reporting is also typically handled by the field crew. In some cases, the NCC does not participate in the LV-fault management process at all.

4.3.3 Electrical safety during fault management

The environmental conditions are often difficult during fault management and those involved in fault management are typically in a rush, especially during a major power disruption. Even so, safety issues must be considered in compliance with the standard SFS 6002 “Safety at electrical work”. This standard has been approved by Tukes, the electrical safety authority in Finland and by applying the instructions found in the standard, the requirements set by the Electrical Safety Act are met. [69, p. 5], [70], [71] This chapter briefly discusses the basic and most important safety issues and perspectives that must be considered during fault management.

According to SFS 6002, the operator is responsible for the safe operation of an electrical installation during electrical work. [69, p. 10] Therefore an operator’s situational awareness must be at a high level, since during a major power disruption, there are typically numerous work locations and multiple field crews in each location, possibly from multiple different contractors. Due to this reason, MV-switching operations in the field must be approved by the operator before they are carried out. Also a work permit must be given by the operator before the field crew may proceed with any repair work. To avoid misunderstandings, the instructions and orders given by the operator must be short and clear. Typically the field crew acknowledges the orders by repeating them for the operator over the phone. [72] According to SFS 6002, electrical work may not begin/must be stopped if adverse environmental conditions are present (e.g. heavy fog, lightning, heavy rain, strong wind). [69, p. 24] Due to this, repair work often cannot be started during the first hours of a major power disruption. Before beginning with the electrical work, five important safety rules should be applied to ensure that the work location is dead. [69, p. 25] These five rules, defined by SFS 6002 are:

- Complete disconnection
- Blocking of the reconnection of voltage
- Verification of absence of voltage of the installation
- Work earthing
- Protection against live parts in the vicinity

To ensure that the safety rules are applied at the work site, a person in control of work activity must be nominated. This person is typically a member of the field crew dispatched to the location and is responsible for the electrical safety on site. [69, pp. 11, 55-56] From the point of view of legislation, there are no differences regarding electrical safety during a major power disruption and a normal situation. Therefore e.g. temporary repairs must comply with all regulations that are applied during a normal situation. [73, pp. 71-74] Especially during major power disruptions, it is necessary to ensure that both operators and field crews have sufficient amount of resting time as fatigue has been proven to predispose to mistakes that lead to safety hazards. [73, p. 74] Finally, according to [73, p. 23], lack of routine may also affect electrical safety if the persons participating in fault management are not regularly involved with electrical safety related issues. Therefore, regular revision and training should be required from all personnel participating in fault management.

5. MICROSCADA PRO DMS600

The DMS600 is a part of ABB's MicroSCADA Pro product family. The other products in the family are SYS600 and SYS600C. SYS600 (later, MicroSCADA) is the traditional SCADA system, used for real-time monitoring and control of the primary and secondary equipment in the network. The SYS600C is a solid-state computer that utilizes information distributed in different locations. It can be used as a communication gateway in e.g. primary substations or as a completely redundant control system with a preinstalled SYS600. [74, pp. 20-25]

The two main applications of DMS600 are DMS600 Network Editor (NE) and DMS600 Workstation (WS). From a system point of view, DMS600 NE acts as a Network Information System but is an integral part of the DMS600 product. However, DMS600 can be alternatively integrated with Network Information Systems from other vendors. Integration with other vendors' SCADA systems is also possible, using OPC Data Access interface, although the smoothest operation is achieved with MicroSCADA. With MicroSCADA, it is also possible to use the older SCIL-API interface. Numerous licenses and sublicenses can be chosen to unlock more functionalities. The chosen license also defines the dimensions of the network database (maximum network size in terms of components). The DMS600 software runs on Microsoft Windows environment and relational database servers are used to store data (e.g. Oracle and Microsoft SQL Server). DMS600 commonly uses two databases: the network database and DMS database. Static network component data is stored in the network database and the DMS database contains e.g. dynamic switching state information and outage report data. The system also supports hot-standby with a replication feature. [75]

DMS600 system also includes two background applications that are used for running server-side functionalities; DMS600 Server Application (SA) and DMS600 Service Framework. The server application is mainly used to serve communication between DMS600 and MicroSCADA, when using SCIL-API interface. When using SCIL-API, DMS600 SA handles, for example, all switching state updates, measurements, alarms and sends fault data from MicroSCADA to DMS600 WS. The Service Framework monitors the background modules that are used in DMS600 environment. [76, pp. 79-85] The main modules running over the Service Framework are:

- OPC Client
- Outage Info Sender
- Topo Component
- Fault Service

The OPC client handles the communication between DMS600 and the used SCADA system, when SCIL-API is not used. This is the recommended configuration and can be used with any compatible OPC DA server to integrate other vendor's SCADA systems with DMS600. [75, pp. 25-26] The Outage Info Sender is a module that automatically monitors the real-time outage data based on received socket messages and generates an XML file containing network outage information. This file can then be used to provide outage notification services for DSO's customers. An example of this is presented later in Figure 14. The used socket messages are sent by Topo Component, which is a module that monitors the switching state of the network and updates unsupplied transformers to the database. Finally, the Fault Service is a module that monitors the OPC interface between the used SCADA and DMS600. It detects circuit breaker trips and creates fault packages that are required to initiate fault management in DMS600 WS. These fault packages contain information regarding e.g. the tripped circuit breaker, fault type, event time stamps and measured fault current. [76, pp. 83-84] If SCIL-API is used, the fault packages are created by DMS600 SA. Alternatively, DMS600 SA can also be configured to create the fault packages when using OPC interface. [24, pp. 53-55] In addition to the aforementioned modules, there are also numerous other modules that can be run over the service framework. These are often DSO-specific and can be used as an interface between the DMS and e.g. external NIS and WMS.

Henceforth, this chapter focuses mainly on DMS600 WS and the features of DMS600 NE and the background applications are not discussed further. An overview of the main functions is first provided in chapter 5.1 and later on, the fault management functions are introduced in more detail.

5.1 Main functions of DMS600 WS

The DMS600 WS extends the traditional features of SCADA with a large variety of functions. The main operational functions are listed below with the most important features bolded:

- **Network topology management**
- Network protection and analysis
- AMR Integration for LV-network management
- **Operation planning and management of maintenance outages**
- **Fault management**
- Data analysis

To fully exploit some of the features, a corresponding license has to be acquired and also a certain level of network automation integrated with the system is required. [75, p. 59] The DMS600 WS contains a Graphical User Interface (GUI), which is presented in Figure 11. In the figure, a geographical network window with a topological coloring selected is visible, along with a diagram presentation of a primary substation. General toolbar for the most commonly used features is also visible and the connection statuses with databases and other components are shown in a separate status bar on the right.

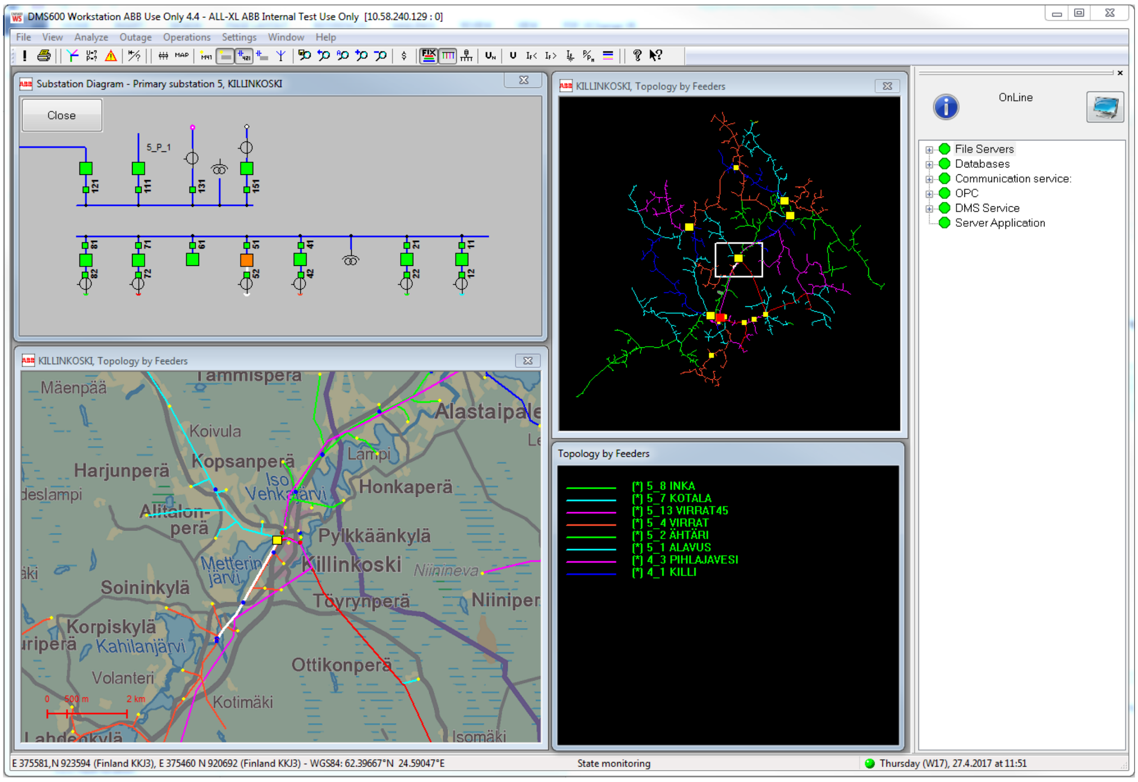

Figure 11. *GUI of DMS600 WS with windows for geographical network view, substation diagram and network overview visible.*

The view can be customized by the user to best suit his/her needs. From the toolbar, the coloring of the network can be quickly switched to check for e.g. constraint violations in the network. The user-defined visual presentation of the network is a core function in topology management.

Overall, DMS600 WS can be operated in 7 different modes:

- State monitoring mode
- Offline mode
- Disturbance mode
- Simulation mode
- Switching planning mode
- Automatic Fault Isolation and Restoration mode
- Optimization mode

During real time state monitoring, power flow calculations are continuously run on the background. The topology of the network is updated if new switching state information is received from SCADA or when the user operates manual switching components in

DMS600 WS. In offline mode, the OPC interface is disabled and switching states are not updated automatically. The disturbance mode may be used in e.g. major power disruption, since it enhances the performance of DMS600 WS by disabling some functionalities. The simulation mode can be used for analysis based on historical events or forecasted load data. For example switching states can be saved in state monitoring mode and then loaded in simulation mode for later analysis. Switching sequences can be planned and recorded in switching planning mode and in automatic fault isolation and restoration mode, the system automatically initiates fault location, isolation and restoration procedure. Finally, optimization mode can be used for network reconfiguration to reduce power losses. [77, pp. 75-76]

Since this thesis focuses on fault management, it is not reasonable to discuss all features of the system that are not related to the main topic. The fault management functions available in the latest released version of DMS600 (4.4 Feature Pack 1 Hotfix 3) are introduced in the following chapters.

5.2 Fault management in DMS600 WS

DMS600 WS contains functions for both MV- and LV-fault management. However, the LV-fault management functionalities are mostly limited to reporting and displaying AMR events, alarms and measurements. The MV-fault management provides a wider range of functionalities and MV-fault management is one of the core features of DMS600 WS. Hence, this chapter focuses mainly on the MV-fault management in DMS600 WS. In MV-fault management, the main functions are:

- Fault location
- Fault isolation and restoration
- Field crew management
- Customer service and notification
- Fault reporting and archiving

Overview of the fault management interfaces is presented in Figure 12. The fault management window on the top right is used to manage the ongoing faults. It shows the ongoing faults and information regarding them (e.g. starting time, faulted feeder, fault current, fault state etc.) and most of the fault management functions are used through this interface. It is also possible to define fault handling areas, in which case only the faults originating from the selected fault handling area(s) are visible in the fault management interface. This function can be used in e.g. major power disruption situation, where the fault handling responsibilities might be divided to several operators, based on geographical areas. The further information presented in the outage information window (top-left in Figure 12) can be configured by the user.

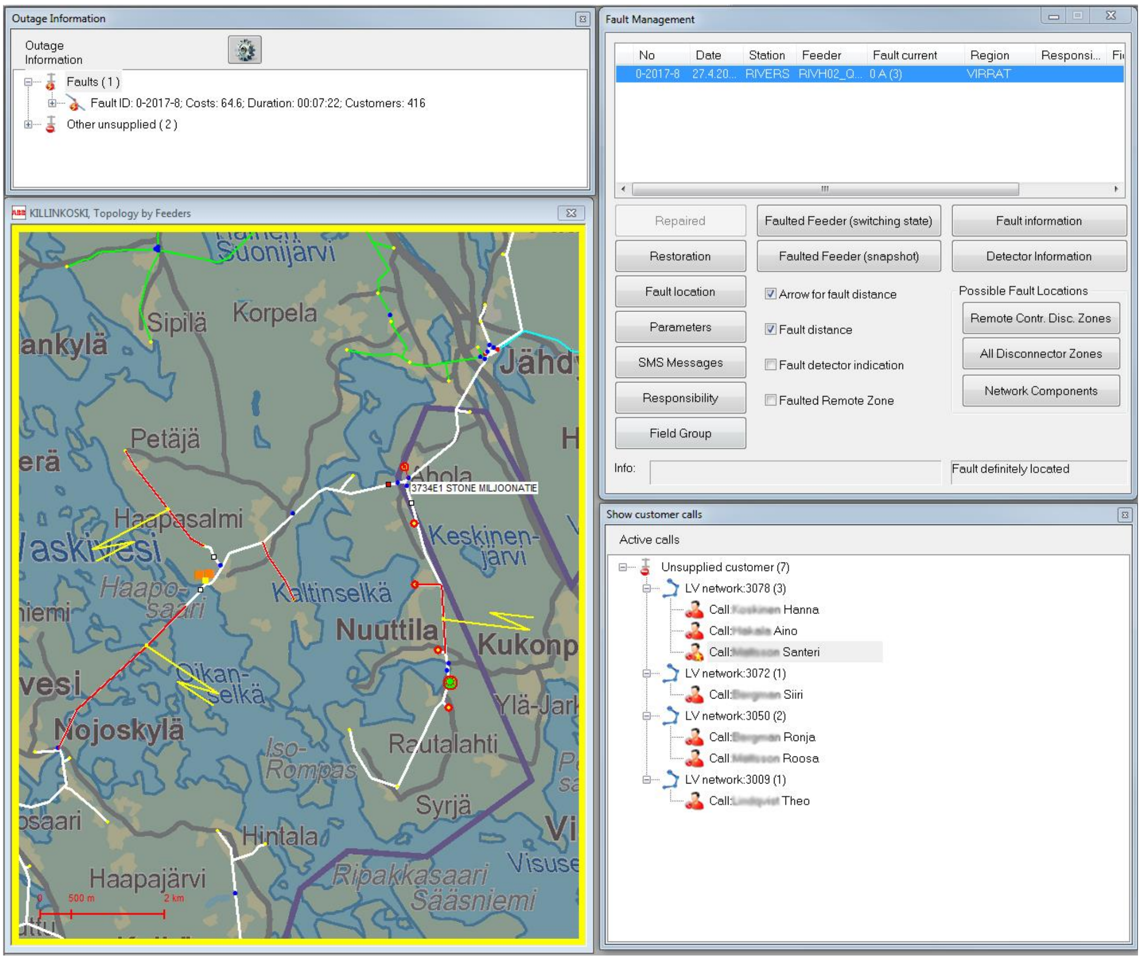

Figure 12. *Overview of the fault management interfaces in DMS600 WS.*

In Figure 12, information regarding the cost of Non-Delivered Energy (NDE), outage duration and number of unsupplied customers is shown but other information could also be presented. The disturbance call window aids the operator in managing customer calls and information regarding the caller can be found quickly using this feature. The different fault management functionalities and their principles of operation are discussed with more detail in corresponding chapters below.

5.2.1 Fault location

The current fault location function of DMS600 WS can be utilized with permanent faults in neutral isolated, compensated or neutral earthed networks with radial operation. The fault location is determined based on

- Fault distance calculation
- Fault detector data
- Line section types (overhead line/underground cable)
- Overloading conditions for network components

Fault distance calculation requires measured fault current or impedance data from the protective relay. Although calculation for both short-circuits and earth-faults is supported, earth-faults are often not located due to lack of accurate reactance measurements, especially in compensated networks. Since compensated networks are becoming increasingly common in Finland, the current fault distance calculation is mostly not feasible for earth faults in Finnish distribution networks. If the calculation is successful, the location is pinpointed on the map as a lightning bolt (illustrated in Figure 12). Since distribution network is often branched, multiple points with calculated fault current or reactance matching the measured value may be found. This problem is also visible in Figure 12, with multiple lightning bolts displayed on the map. [75, pp. 78-80]

It is possible to integrate remote-readable fault indicators with DMS600 WS to overcome the aforementioned problem. It is also possible to implement on-site readable fault detectors but then the detector states have to be updated manually from the DMS600 WS interface. The state of the fault indicator is displayed on the map to help the operator in determining the fault location. In addition, the indicator information affects the system's own inference logic, which is based on the calculated fault distance and the fault indicator states. The line section types and overloading of network components also have an effect on the inference logic. [75, pp. 78-80] The inference system utilizes fuzzy logic and its extension, fuzzy sets to combine the aforementioned information. In fuzzy logic, the truth value of a variable may be any real number between 0 and 1, whereas in Boolean logic, the truth value may be only 0 or 1. Fuzzy sets have elements that have a certain degree of membership between 0 and 1. In the inference model, this degree of membership is calculated for each unsupplied zone, using specific user-defined certainty factors for different types of information. These certainty factors have to be set carefully, as they affect the inferencing results significantly. Typically the certainty factors for calculated fault distance and fault indicator data are set highest as they are generally more reliable and act as a basis for the inferencing process. [66, pp. 23-28,79-86], [67, pp. 43-48] More information on the research behind the modelling is available in [66] and [67].

After calculating the likelihoods for each unsupplied zone, the system then further determines the faulted zone, based on the calculated likelihoods and limits set by the user. A lower limit for the faulted zone has to be set, along with an upper limit for the healthy zones. These limits must be met to allow for a "definite" location of the fault. An example is presented in Figure 13, where the aforementioned limits have been set to 0.5 and 0.3. Since the likelihood of the most probable zone is 0.55 and all other zones have likelihoods of 0.15, the zone with likelihood of 0.55 is chosen as the fault location. [75, pp. 78-80]

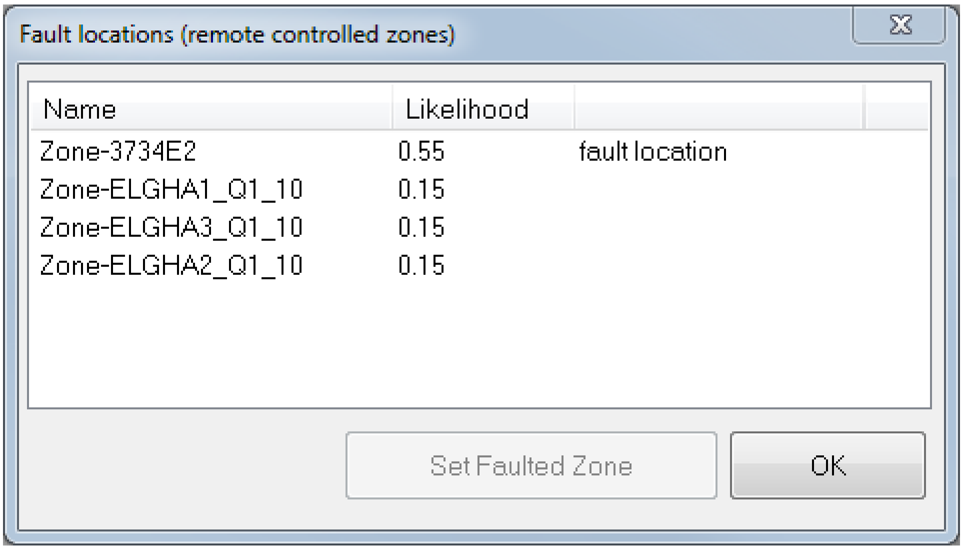

Figure 13. *Calculated likelihoods of faultiness for remote-controlled zones.*

This “definite” fault location is utilized in the automatic fault isolation and restoration feature which is described in the following chapter.

5.2.2 Fault isolation and restoration

The fault isolation and restoration function provides support for planning the isolation and restoration switchings in a fault situation. To enable the use of this function, a faulted zone must be ‘definitely’ determined, either automatically by the previously described inference logic or manually by the user. Based on the determined fault location, the system generates a switching sequence to isolate the fault and to restore supply to as many remote-controlled zones as possible. Constraints for technical limits and protection are taken into account while generating the sequence. These constraints include e.g. voltage drops, detection ability to overcurrent and load levels. The limits for each constraint can be defined from the settings. After the sequence has been generated, it can be executed either manually by the operator or automatically with MicroSCADA, permitting automatic fault isolation and restoration. [75, pp. 80-81]

In automatic fault isolation and restoration mode, the created switching sequences are sent to MicroSCADA, which checks the acceptability of the sequence (e.g. whether the switching devices included in the sequence can be operated) and then either begins to execute the sequence or rejects it. The automatic execution of the sequence may be started either automatically or after operator’s approval. If a sequence is rejected by MicroSCADA, DMS600 WS attempts to generate a new sequence that excludes the unaccepted switching devices. Otherwise MicroSCADA begins to execute the sequence step-by-step. If any step could not be executed successfully, the process is aborted. Currently, the automatic fault isolation and restoration mode can only manage one fault at a time and is only applicable with MicroSCADA Pro SYS600 or its predecessor SYS500 version 8.4.2 or higher. [75, p. 81], [77, pp. 155-158]

5.2.3 Field crew management

Field crew management function is used to display the field crews on the map, according to their current location. This allows for more efficient guiding of field crews when operating manual disconnectors during fault management. The locations can be maintained automatically using GPS data or by manually setting their location. Other information regarding the field crew can also be stored in the system. This information may include the names of the crew members, their training, phone numbers and the equipment the crew has with them. The data content of the field crews in the database can be expanded according to the user's needs. [75, p. 89], [77, pp. 98-101]

Currently, the field crew management is actually a separate function from the fault management interface and these functions are not integrated with each other. However, it is possible to keep track of the field crew dispatched to a certain fault by using the free text field for field group in the fault management interface.

5.2.4 Customer service and notification

In case of a disturbance call, the customer service function allows for quick search for information and location of the customer, based on name, customer code or other information available. The information is based on customer data from the network database. With this function, it is also possible to browse the customer's interruption and call history. Information provided by the customer can be added to the disturbance data form to be used in the fault management process (e.g. fault location). These appear as "findings" in DMS600 WS. [75, p. 86], [77, pp. 106-110] The disturbance data form feature was originally developed for export customers as they had need for a simple customer service feature. Finnish DMS600 customers mainly use external systems for these purposes but importing findings from them is also possible.

DMS600 WS offers multiple customer notification functionalities via the Outage Info Sender module. The module provides information for e.g. web outage maps on the DSOs' websites and SMS-messages that are used to inform customers about ongoing faults. SMS messages can be sent automatically to unsupplied customers after a fault has been detected or manually from the fault management interface. The content of the messages can be predefined or manually typed for each case. Usually at least the status of the fault management process and an estimation of the duration is provided, according to the obligations of the Electricity Market Act. An example of a web outage map of a DMS600 customer is presented in Figure 14.

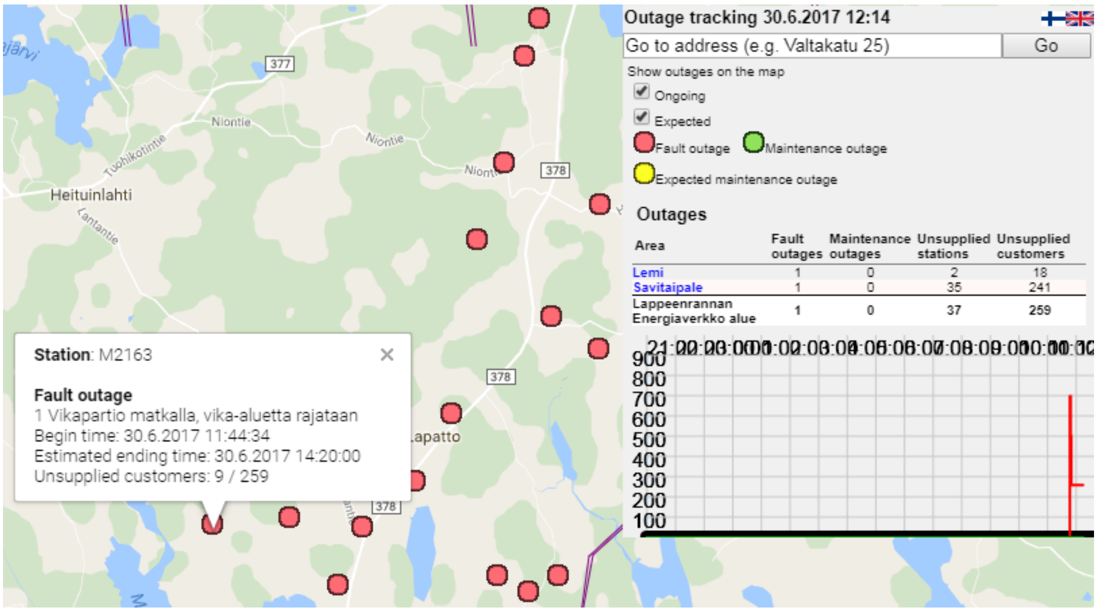

Figure 14. *Web outage map of a certain DMS600 customer.*

The estimated duration and fault status that are displayed on the outage map are also updated from the fault management interface. In addition, the DMS600 WS can be integrated with a telephone answering machine (TAM) to automatically generate a voice message containing the fault status and the estimated duration. [75, p. 90]

5.2.5 Fault reporting and archiving

Due to the extensive reporting requirements from the Energy Authority and Finnish Energy, the fault reporting functionality is one of the most important functions of DMS600 WS. The fault reports can be utilized to manage comprehensive information regarding the occurred faults. The reports typically include information regarding:

- The duration of the fault (starting times, ending times, breaks)
- The name and code of the faulted feeder and primary substation
- Number of customers and secondary substations affected by the fault
- Non-delivered energy, customer hours
- Switching actions executed during the fault
- The actual fault location
- Information required by the energy authority (interruption type, fault reason)
- Other information regarding e.g. the fault type, fault current and the persons responsible for handling the fault

In each fault report, the fault is divided into smaller outage areas based on the outage duration in each area. These areas together form the key figures for the whole fault. Most of the information listed above is generated automatically after the fault has been repaired and the report management initiated. However, some information has to be filled in manually. It is also possible to create the reports entirely manually. Faults can be reported immediately after a fault has been repaired or later through the fault list. Some information (e.g. the actual location of the fault) can be added to the reports even during a fault. [75, pp. 87-88], [77, pp. 194-204]

The report management interface is presented in Figure 15. All fault reporting functionalities are included in the interface. Separate tabs for reviewing and editing the outage areas, additional data and fault location are available but they are used through the report management interface. The "additional data" tab contains most of the information that has to be filled in manually and includes information regarding e.g. the faulted feeder, interruption type, fault reason and environmental conditions. The "fault location" tab is used to add the exact fault location to the report manually by pointing the location on the map.

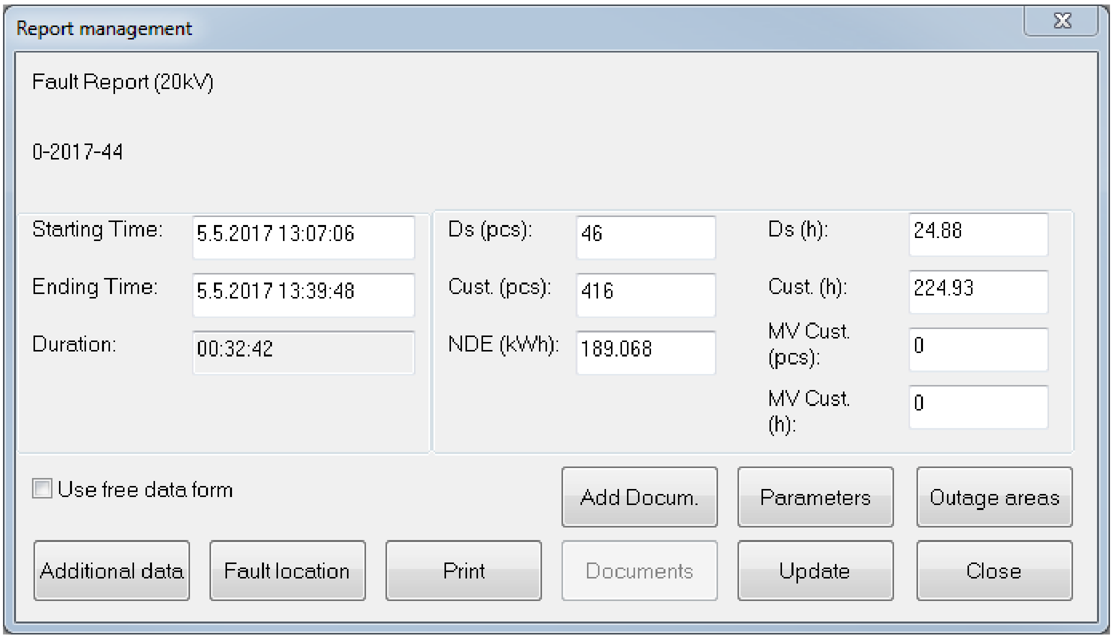

Figure 15. *Report management interface of DMS600 WS.*

After a fault has been reported, it is moved to the fault archives. Historical faults can be reviewed through the archives. The switching state is saved in the beginning of each fault and the historical faults can be re-opened in simulation mode. This enables later simulations and examinations of historical faults. In addition to MV faults, the archives also contain reports for reclosings, LV-faults and maintenance outages. In case of an LV-fault, the report has to be created manually and most of the information has to be filled in by the user. However, LV-faults are often not reported by operators using DMS600 WS. Instead they are imported from e.g. WMS, where the information has been filled in by the field crew. [75, pp. 87-88], [77, pp. 194-204]

In addition to the fault reporting functionalities in DMS600 WS, more extensive reporting tools are available with the reporting services of DMS600. The reporting services are an external browser based tool that are used for generating e.g. the annual authority reports for the Energy Authority. The reporting services use the DMS600 databases and any information from the databases can be extracted to generate different types of with the Structured Query Language (SQL).

6. FAULT SIMULATIONS

Despite many fault management functions available, not all of them are actively used, according to previous customer feedback. Therefore two functions were chosen for a more thorough testing and examination; the fault location function and the automatic fault isolation and restoration function. Currently, the automatic fault isolation and restoration is not actively used by any of the DMS600 WS customers. Also, since the fault location functionality forms the basis for the operation of the automatic sequence, it was also chosen for testing. The operation and feasibility of these functions were tested in an actual network environment by carrying out fault simulations. The simulations were run in the copied environments of two DMS600 WS customers. The network and DMS databases of these two customers were imported in February 2017 to allow for the re-simulation and examination of the most recent faults. In addition to the Graphical User Interface (GUI) of DMS600 WS, data was also gathered straight from the databases, utilizing queries with Microsoft SQL Server Management Studio, which is a GUI tool for configuring, managing and administering the components within the SQL Server.

The data gathered from the simulations was also used to estimate the potential benefit available from the use of automatic fault isolation and restoration function. Based on the simulations, a rough estimate for the cost savings in terms of KAH-value was calculated. The results of the simulations were also presented to the DSOs representatives during the interviews discussed in chapter 7. Based on their expertise, they were asked to evaluate if the results and conclusion were in fact realistic and consistent with their experiences.

The simulations carried out to examine the fault location function are discussed in chapter 6.1 and the testing of the automatic fault isolation and restoration function is reviewed in chapter 6.2, respectively. Chapter 6.3 discusses the potential benefits of the automatic fault isolation and restoration. The DSO feedback regarding the simulations is discussed later in chapter 7.1.

6.1 Fault location simulations

The aim of the fault location simulations was to evaluate the efficiency and accuracy of the current fault location function. The information gathered was also used in projecting the possible financial benefits available from the use of automatic fault isolation and restoration. Fault location simulations were first carried out by simulating the actual MV-faults from the fault archives of a rural DSO, using the simulation mode of the DMS600 WS. The original idea was to repeat the simulations in the environments of two other rural DSOs. Fault archives for the year 2016 were used in the simulations, since it was the most recent complete archive available for DSO 1 and DSO 2. However the third DSO's environment could not be imported from the DSO's server and hence the simulations were to be carried out using the two environments available. When using the environment of DSO 2, it was quickly determined that there is no fault current data available from majority of the primary substations of DSO 2. Since DSO 2 also had no fault indicators installed, this meant that the fault location function would not be able to determine the fault location effectively in DSO 2's environment. Hence, it was not reasonable to proceed further with DSO 2's environment and only the environment of DSO 1 was used. Some key figures regarding the 2016 fault archives of DSOs 1 and 2 are presented in Table 3.

Table 3. *Key figures from the 2016 fault archives of DSOs 1 and 2.*

Quantity	DSO 1	DSO 2
Total faults (pcs.)	1048	898
Short-circuits (pcs. / % of total)	918 / 87.6	571 / 63.6
Earth faults (pcs. / % of total)	129 / 12.3	326 / 36.3
Other faults (pcs. / % of total)	1 / 0.1	1 / 0.1
Percentage of faults with $I_k > 100\ A$ *(%)*	20.4	2.2

The previously described problem with DSO 2's environment is reflected in Table 3, where the percentage of faults with fault current higher than 100 A is visible. With the percentage being 2.2 %, it is clear that there are not many faults that can be located with the fault distance calculation. Even in the case of DSO 1, majority of the faults had fault current of 0 A. This means that there is no fault current measurement data attached to the fault report and so it is certain that in these cases the fault distance calculation is unable to locate the fault, since there were also no fault impedance measurements available. Thus, only short-circuit faults were considered but even then there were a lot of faults left, having fault currents of less than 100 A. In these cases the fault current data may not have been available at the time, the fault type may have been defined incorrectly (e.g. earth fault as a short-circuit) or there may have been some measurement or scaling errors. Whatever the reason, in these cases the fault current on the report does not correspond to reality and therefore the fault distance calculation is unable to determine the fault location. Hence, to reduce the number of simulations required, a rough lower limit for the fault current was experimentally determined. Based on the experiments, it was determined that in the environment of DSO 1, faults having fault current of less than 350 A cannot be located with the fault distance calculation and hence, only faults with fault current higher than 350 A were thoroughly examined. Using this limitation, there were 204 faults that were re-simulated from the 2016 archives.

DSO 1 had a few remote-readable fault indicators installed but the historical statuses of the fault indicators are not written in the database when the fault is reported and archived and therefore they do not operate when re-simulating the faults. Thus, in these simulations, it was assumed that the fault indicators always operated correctly and their states were set manually, according to the actual fault location information filled in by the operator. If the actual fault location was not available, the indicator states were left untouched. Due to the very small amount of installed fault indicators, this should not have significant impact on the results.

Since the fault distance calculation is performed dynamically only when the fault is active, neither the calculated fault locations nor the information regarding the status of the inference function are written in the fault database. Therefore faults had to be re-simulated separately one by one from the 2016 archives. Based on the outcome of the simulations, different types of information were gathered. These were:

1. Information regarding whether the fault distance calculation was successful or not
2. Information regarding whether the fault was definitely located or not, according to the parameters used
3. Information regarding the validity of the fault location if the fault was definitely located, i.e. if the automatically selected remote-controlled zone was actually faulty
4. Information regarding whether the zone with the highest likelihood was actually faulty or not and reversely whether the zone with the lowest likelihood was healthy or not

The first two items do not consider the validity of the performed actions, but only whether they could be carried out or not. Validity of the performed actions is considered in items 3 and 4, based on the actual fault location filled in by the operator during the fault management process. The item 4 was mainly additional information and was collected to study, whether the fault location function could rule out at least one healthy zone with high certainty even if it can’t accurately determine the faulted one. This could be used e.g. to allow limited automatic restoration to zones that are determined healthy with a high certainty. Similarly, the faultiness of the highest likelihood zone was examined to consider the possibility of configuring the inference logic to always choose the highest likelihood zone as the definite fault location.

The simulations were carried out twice with two different sets of parameters for the inference function. First the default settings from the environment of DSO 1 were used and then, according to the results, the parameters were adjusted in order to increase the amount of definitely located faults. The parameters for the simulation rounds are presented below in Table 4.

Table 4. The parameters used in the fault location simulations.

Round	Lower limit for the faulted zone	Upper limit for other zones
1	0.8	0.5
2	0.3	0.3

The faults were classified as "*correctly located*" if the chosen remote-controlled zone contained at least one actual fault location. An example is presented in Figure 16 where the yellow highlighted zone has been chosen as the definite fault location. The two stars mark the actual fault locations and since they are located within the yellow zone, the inference is correct in this case.

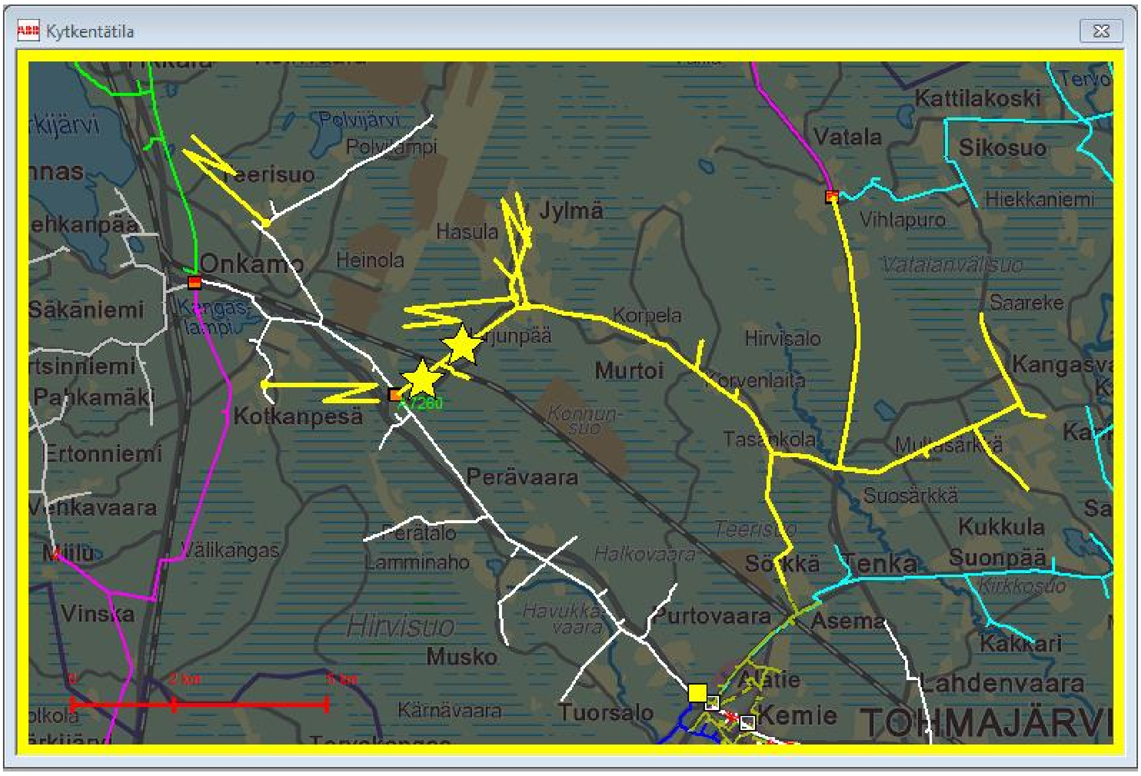

Figure 16. An example of a correctly located fault.

Correspondingly, if the actual fault locations were outside the chosen zone, the fault was classified as "*incorrectly located*". If there were no actual fault locations available, the fault was classified as "*fault location unknown*". Also, if multiple fault locations were calculated and the inference function was unable to determine the faulted zone within the set limits, the fault was classified as "*inaccurately located*".

The results of the simulations with both sets of parameters are presented in Table 5, classified as previously described. As can be seen, fault distance could be calculated for 143 faults, which accounts for 13.6 % of the faults in the 2016 archives of DSO 1. By adjusting the parameters, the amount of definitely located faults among these 143 was increased from 96 to 125. The second set of parameters decreased the certainty requirements for the likelihoods of the zones and therefore the amount of both correctly and incorrectly located faults was increased, whereas the amount of inaccurately located faults was reduced. Among the 1048 faults in the 2016 archives, there were numerous cases where the fault had been created manually by the operator to fix SMS and web outage notification issues for some customers. In these cases some outage areas had not been linked to an ongoing fault in DMS600 WS, in which case another fault has to be created manually for these areas to ensure the functioning of outage notification. This increases the amount of total faults in the archives and in turn reduces the percentage of located faults, since the manually created faults never include fault current data. Hence, in practical terms, the fault distance calculation could be performed for slightly more than 13.6 % of the faults occurred.

Table 5. *Results of the fault location simulations for the studied set.*

	Parameters 1			**Parameters 2**		
Item	Pcs.	% of total faults	% of faults with I_k > 350 A	Pcs.	% of total faults	% of faults with I_k > 350 A
Fault distance calculated	143	13.6	70.1	143	13.6	70.1
Fault definitely located	96	9.2	47.1	125	11.9	61.3
Correctly located	45	4.3	22.1	54	5.2	26.5
Incorrectly located	23	2.2	11.3	35	3.3	17.2
Inaccurately located	36	3.4	17.6	15	1.4	7.4
Unknown fault location	39	3.7	19.1	39	3.7	19.1
Not located	61	5.8	29.9	61	5.8	29.9

The inference function was able to choose the correct zone in most cases where the fault was definitely located. However, most of the feeders only consisted of a few (2-4) remote-controlled zones, which increased the chances of choosing the correct zone, even if the calculated locations did not accurately match the actual fault location. I.e. it is likely that increasing the amount of RCDs in the network would likely result in less faults being correctly located. In addition, there were also a few feeders with no remote-controlled switching devices installed, i.e. the feeder consisted of only one zone and therefore the chosen zone was automatically correct. Even in the used environment, many faults were also incorrectly located. The most common reason for this was that, although one of the calculated locations was fairly accurate, there were multiple other calculated locations in different zones, which caused DMS600 WS to choose incorrectly. There were also some cases where none of the calculated locations were anywhere near the actual fault location. In these cases the fault current was either incorrect or the operator had not marked all fault locations to the report.

Of the studied set of 204 faults, 45 were correctly located with parameters 1 and 54 with parameters 2. Even with the adjusted parameters, only around 5 % of the total annual

MV-faults could be located correctly and definitely, which already prevents wide utilization of the current automatic fault isolation and restoration function, since definite fault location is required. The calculated fault locations however do provide the operator with useful information of possible fault locations, of which the operator might be able to determine the correct one, based on his/her experience and intuition.

Furthermore, there were still 61 faults in the studied set of 204 faults that could not be located using the fault distance calculation, which accounts for roughly 30 % of the studied set. A common reason for the failure of the calculation was incorrect fault current. In these cases the fault current was either lower than the lowest possible fault current at the end of the feeder or higher than the highest possible fault current at the feeding circuit breaker. This means that there has either been a measurement error at the primary substation or the fault current data has distorted somewhere during data transfer to the DMS. Another reason for failure was that, in some cases, the network used in the simulations did not correspond to the one that existed at the time of the fault. This was a result of a later network modification, e.g. adding of a new network section or deleting an old one after the fault had been reported and archived. This causes DMS600 WS to use the historical switching state in the currently existing network and prevents the use of fault distance calculation in re-simulations.

As was previously described, additional information regarding the actual faultiness of the highest likelihood zone and the healthiness of the lowest likelihood zone was also gathered during the simulations. This information was gathered for faults that had the actual fault location added to the report and consisted of more than one remote-controlled zone. The rates are presented in Table 6.

Table 6. *Faultiness and healthiness rates of the highest and lowest likelihood zones.*

Item	**Pcs.**	**% of studied set**
Actual fault located in the zone with the highest likelihood	44	48.9
Actual fault located outside the zone with the lowest likelihood	64	71.1
Total faults studied	90	100.0

Of the studied set, the actual fault was located in the highest likelihood zone in roughly half of the studied cases and most of the lowest likelihood zones were healthy. However, the previously described impact regarding the amount of remote-controlled zones also applies to these results. Therefore no significant conclusions can be based on these results, although it is likely that with high number of remote-controlled zones in a feeder, the lowest likelihood zone can be assumed healthy with a fairly good accuracy. On the contrary, the accuracy of a fault being actually located in the highest likelihood zone were less than 50 % and the rate would be even lower for feeders with high amount of remote-controlled zones. Therefore configuring the inference logic to always choose the highest likelihood zone would often result in a circuit breaker trip and aborting of the restoration sequence.

Finally, after a brief comparison between the most recent yearly fault archives of DSO 1, it was noted that the percentage of faults with fault current higher than 100 A varied significantly between years 2012-2016. For example in 2014, the percentage was 2.8 % while it was 20.4 % in the 2016 archives, which were used in these simulations. The percentages were particularly low in the 2013 and 2014 archives, which indicates that significantly smaller amount of fault current data had been transferred to DMS. If these archives had been used in these simulations, the results would have likely been different and especially the percentage of located faults would have been considerably smaller. However, it is likely that this issue was mainly resulting from configuration changes to the DMS Fault Service during 2013-2014 and was therefore temporary.

6.2 Testing of the automatic fault isolation and restoration

To evaluate the operation of the automatic fault isolation and restoration function, another set of simulations was carried out in the environment of DSO 1. In this case, the simulations were not directly based on historical faults and instead the faults were created manually. The testing was carried out for 20 different feeders, consisting of at least three remote-controlled zones. For each feeder, the location of the faulted zone was manually varied along the feeder so that first the faulted zone was located at the beginning of the feeder, then in the middle section and finally at the end of the feeder. The testing was carried out in two different switching states; normal and disturbed. In a normal state, there were no other unsupplied feeders that could affect the generation of the sequence. In a disturbed state, at least one adjacent feeder that had an open connection point with the studied feeder was unsupplied. The idea was to simulate a situation where multiple faults are simultaneously active in the same geographical area. The unsupplied adjacent feeder was chosen so that DMS600 WS had used it in the restoration sequence for normal state and therefore had to alter the sequence from the previous situation. An example of a simulation carried out in a disturbed state is presented in Figure 17.

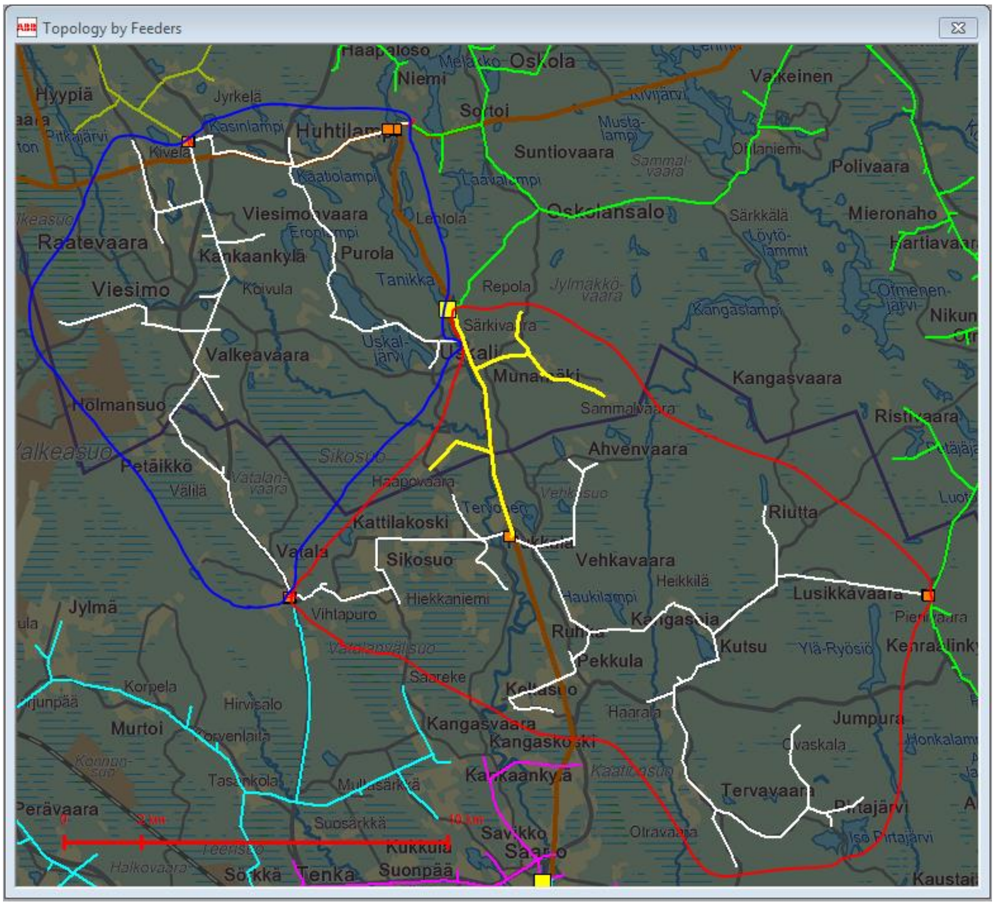

__Figure 17.__ Testing simulation with network in a disturbed state. The studied feeder is outlined in red and the adjacent unsupplied feeder in blue.

In Figure 17 the studied feeder is outlined in red with the yellow highlighted zone containing the fault and the blue outlined feeder is the adjacent one, set unsupplied for disturbed state simulation. The aim of these simulations was to determine, whether the switching sequences generated are feasible in different situations. The percentage of restored customers in each case was also determined for later use in evaluating the benefits of automatic fault isolation and restoration.

The generated sequences were examined manually in each case. The sequences were classified as follows:

Ok	=	the sequence was rational and all possible healthy zones were restored, regarding the technical constraints
Bad	=	some constraints were violated or some zones were not restored even though there were no constraint violations
Other	=	the sequence restored all zones without constraint violations but contained some unnecessary switching operations

The DSO 1's default constraint limits were used, which allowed a maximum of 7 % voltage drop and a maximum of 100 % load level and short-circuit capacity. For short-circuit and earth fault detection, minimum of 100 % of the corresponding relay setting was required. These constraints were checked manually for all cases using the corresponding coloring modes of DMS600 WS. The results for the simulations in both normal and disturbed states are presented in Table 7 and Table 8.

Table 7. *Results of the testing of the automatic fault isolation and restoration function in a normal state.*

		Location of the faulted zone			
Sequence status		Beginning	Middle	End	Total
Ok	Pcs.	13	14	19	46
	%	65.0	70.0	95.0	76.7
Bad	Pcs.	6	4	0	10
	%	30.0	20.0	0.0	16.7
Other	Pcs.	1	2	1	4
	%	5.0	10.0	5.0	6.7
Total	Pcs.	20	20	20	60

Table 8. *Results of the testing of the automatic fault isolation and restoration function in a disturbed state.*

		Location of the faulted zone			
Sequence status		Beginning	Middle	End	Total
Ok	Pcs.	13	16	19	48
	%	65.0	80.0	95.0	80.0
Bad	Pcs.	6	3	0	9
	%	30.0	15.0	0.0	15.0
Other	Pcs.	1	1	1	3
	%	5.0	5.0	5.0	5.0
Total	Pcs.	20	20	20	60

As expected, the generated sequence was feasible in most cases. There were also no significant differences in the results between the two network states. Surprisingly, however, the sequence was incorrect in over 15 % of the studied cases. Apart from one case, these were all result of some zone(s) not being included in the restoration sequence, even though there were no constraint violations, according to manual check. To determine the reason for this, the constraint limits were altered but whatever limits were set in these cases, the problem wasn't solved. Since there is no error log available of the sequence generation, it is difficult to determine, what prevented the restoration of some zones. It was found that the 1 kV network that has been documented in the MV-level in DSO 1's environment, caused the short-circuit detection calculation to operate incorrectly. This originated from the 1 kV LV-switches that had been documented as relays but no settings were determined for them in DMS600 WS. This caused the coloring mode to always present the 1 kV branches in alarm color. Changing the 1 kV relay settings fixed the issue with the coloring mode but did not affect the generation of the sequence in most cases. Even disconnecting the 1 kV branches manually prior to the simulations did not solve the problem and for the time being, it remains unclear what is causing the described problem.

The aforementioned problem, however, is not an electrical safety issue that would definitely prevent the use of the sequence. There was a single case where the generated sequence contained switchings that caused an unacceptable voltage drop. In this case the network was in in an unaccepted state even before the fault. It was later found that, according to loadflow calculations, it is impossible to configure the network to an accepted state in this specific area without altering the primary transformer tap changer settings. None of this, however, explains why the constraint violations were allowed in the sequence, since the pre-fault state of the network should not affect the checking for constraint violations. There were also a few cases where the sequence was seemingly correct but included some unnecessary switching operations. It is likely that these result from the same previously described issue, where DMS600 WS, for some reason, seems to falsely believe that there is a constraint violation and includes so-called “load relief” switchings in the sequence. In total, the generated sequence restored supply for 60.5 percent of the feeder customers on average.

6.3 Potential benefits of automatic fault isolation and restoration

In addition to the actual simulations, the potential benefits achievable from the use of automatic fault isolation and restoration were studied. The idea was to get some notion of the financial benefits achievable and then present the results to the DSOs’ representatives for their evaluation. Since a thorough study of the benefits could solely provide a topic for a thesis, the evaluation carried out in this one was kept rough and as compact as possible. In practice, this was done by calculating an average reduction in the KAH-costs per fault using several assumptions based on the fault archive data and the fault simulations. The results of the fault location simulations were then used to evaluate the achievable benefits on annual basis.

In order to calculate the reduction in KAH-value, data regarding the amount of average customers on a fault and their average disconnected power was gathered from a five-year period, using the 2012–2016 fault archives of DSO 1 and DSO 2. It was assumed that 60.5 % of these customers could be restored using the automatic sequence, based on the earlier simulations. The main issue was to determine the time saved with the use of the automation. It is likely that in a normal situation where the operator is not overburdened with multiple faults, there is little to no benefit available. Instead, the majority of the benefits can be achieved in a major power disruption situation, where there may be dozens of faults to be managed simultaneously. Therefore an estimation of the time saved was created by comparing the durations of remote isolations made by an operator in a normal situation and in a major disruption. However, DMS600 WS includes all switching operations occurred anywhere in the network during a fault in the fault report switching list. Therefore, during a major power disruption, it is nearly impossible to determine all the remote-controlled switching operations that are linked to the studied fault, since lots of other switching operations are also being carried out all over the network and these are included in the switching list as well. Due to this, the outage time of the first outage area (i.e. zone where supply was restored first) was used for both situations when comparing the durations. In practice, the outage time of the first outage area represents the operator's response time and the time used to carry out the first successful isolation. This data was easily readable from the GUI of DMS600 WS and also straight from the database, using simple queries. To ensure that the results were comparable, the switching list was used to check that the first isolation was indeed carried out using RCDs and not manual disconnectors.

The Rauli-storm, which occurred on august 27th, 2016 represented a major power disruption in this study. The data required to compare the durations was gathered from DSO 1's fault archives and Rauli-storm was the worst case in the 2016 archives and was therefore chosen for this study. The progress of the situation during the storm is depicted in Figure 18.

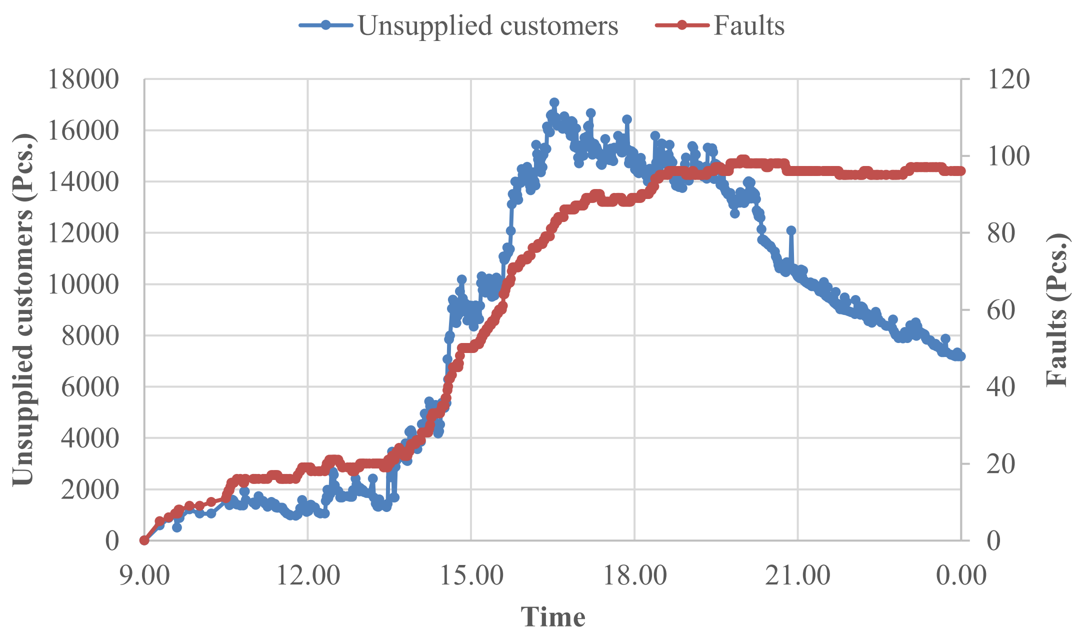

Figure 18. *Progress of the major disruption situation during the Rauli-storm in the network of DSO 1.*

The busiest time in terms of active faults was between 19:00-21:00, when there were 97 active faults on average. The new faults that began during this time period were used in this study. There were a total of 20 faults having starting time in this period. 14 of these were included in calculating the average isolation time for a major power disruption. 6 cases were not included because there either was no data available or the first isolation had not been carried out with RCDs. In this study, cases where only a single fault was active, were used as a normal situation. In these cases the operator could concentrate solely on handling that fault and therefore it represents the easiest scenario. Correspondingly to the major power disruption situation, 14 cases having the first outage area isolated with RCDs were randomly selected for the comparison. Two different examples were created to evaluate the time differences. In both cases it is assumed that the automatic fault isolation and restoration is always able to carry out the switchings as fast as the operator in a normal state. In the first example, the direct difference between the durations is used. This represents the time saved during a major power disruption. In the second example, it is assumed that the operator's average duration for the isolation on an annual basis would be the average of the two durations (i.e. average of the durations in the worst and easiest scenario). This is used to roughly represent the average time saved for all faults on an annual basis.

Since some DSOs do not occupy the NCC during the night, considerable benefits might be derived from the use of automation during nighttime. Therefore, a third example was also created, where the isolation durations for the faults that began during nighttime (22:00-06:00) were gathered and compared to the corresponding durations for faults that began during other time (06:00-22:00). In this example, the durations were gathered straight from the database and the average was calculated using data from all faults in the 2016 archives. The archives of DSO 2 were used in this study, since it was known that their NCC is not occupied during the night. The average durations and their differences for the three examples are presented in Table 9. In examples 1 and 2, duration 1 represents the time it would take for the automatic sequence to carry out the isolation and duration 2 represents the corresponding time for an operator. In example 3 the durations are considerably longer, since data from all faults was used without manual check. This data includes also false cases where the fault was e.g. created for customer notification purposes or no switchings were recorded. However, since these false cases are present in both durations for example 3, the difference should roughly represent the achievable time benefit from the use of automation.

Table 9. *Isolation durations and their differences for three example cases.*

	Example 1	**Example 2**	**Example 3**
Duration 1	0:04:28	0:04:28	0:20:23
Duration 2	0:10:12	0:07:20	0:28:23
Difference	0:05:44	0:02:52	0:08:00

The other data used in the evaluation is presented in Table 10. This includes the average disconnected power per customer, average customers per fault, restored customers per fault and restored power per fault. The restored power is based on the amount of restored customers and their average disconnected power. Hence, in this evaluation it is assumed that the customers and loads are evenly distributed along the feeder.

Table 10. *Additional data used in the evaluation.*

	DSO 1	DSO 2
Average disconnected power/customer (kW)	0.95	0.91
Average customers per fault (Pcs.)	388	487
Restored customers per fault (Pcs.)	235	295
Restored power per fault (kW)	223.25	268.45

Using the data presented in Table 9 and Table 10, the KAH-benefits for a single fault were calculated using Equation (2), which has been derived from Equation (1). This equation only considers the energy-dependent part of the KAH-cost, since the use of automatic fault isolation and restoration has no effect on the initial disconnected power.

$$KAH_B = P_x \times t_y \times 11€/kWh \times \frac{CPI_{2016}}{CPI_{2005}} \tag{2}$$

where

KAH_B = the KAH-benefit

P_x = restored power for fault *x*

t_y = time difference in example *y*

CPI_{2016} = consumer price index of year 2016

CPI_{2005} = consumer price index of year 2005

The calculated KAH-benefits for DSOs 1 and 2 in the three example cases are presented in Table 11. The used ratio of the consumer price indexes was 1.198.

Table 11. *Potential KAH-benefits per fault for DSOs 1 and 2 in three example cases.*

	Example 1	Example 2	Example 3
DSO 1 (€)	281	141	392
DSO 2 (€)	338	169	472

While these values are only rough estimates, it is clear that the biggest benefits can be achieved during a major power disruption or in cases when the NCC is not occupied 24/7. Based on the values presented in Table 11, the benefits on an annual basis would be rather small, using the current logic of DMS600 WS. Only 54 faults were correctly located for year 2016 in DSO 1's environment and therefore, using the average KAH-benefit value for all faults (example 2), would result in annual benefits of less than 8 000 €. In addition, since DMS600 WS is currently able to manage only one fault at a time in automatic fault isolation and restoration mode, the amount would be even smaller. However, adding the ability to manage multiple faults simultaneously and changing the isolation and restoration logic to allow experimental switchings when the fault location is unknown would greatly increase the feasibility of the function. If, for example, all 112 faults that occurred during the nighttime in DSO 2's network in 2016 could have been isolated automatically, they would solely account for a KAH-benefit of over 50 000€.

It is also likely that the values presented in Table 11 are at least somewhat underestimated, since load is usually not distributed evenly along the feeders but is instead concentrated on the beginning of the feeder. The beginning part of the feeder is often less prone to faults (due to e.g. cabled network), and therefore it is likely that the automatic isolation and restoration could often restore supply to these higher load concentration areas, which would result in higher KAH-benefits per fault. In addition, the power used in these evaluations is derived from the non-delivered energy and therefore represents the actual disconnected power while the Energy Authority calculates the power based on the annual energy consumption of the customers. Since most of the outages occur during summertime, for most outages, the actual disconnected power is lower than the yearly average. This results in slightly smaller KAH-values in this study, compared to the actual KAH-values calculated with equation (1).

Overall, it proved difficult to accurately evaluate the KAH-benefits, since they are affected by numerous factors. For example the time it takes for an automatic isolation and restoration sequence to run depends on the used field communication solution and evaluating the duration for operator's isolation accurately is difficult without tedious manual work. However, a conclusion can be drawn that considerable benefits can be achieved during major power disruptions and times when the NCC is not occupied but not with the current isolation logic, unless significant amount of reliable fault detectors are available.

7. DMS600 CUSTOMER INTERVIEWS

In order to develop the fault management functions according to the requirements and wishes of DMS600 customers, a discussion with the representatives of a few DSOs was organized. This insight is valuable in discovering the inadequacies of DMS600 WS. The original idea was to organize a joint meeting with multiple DSOs representatives. However, it proved difficult to find a time that would have suited everyone's schedule and therefore separate interviews were chosen instead. A joint meeting would have provided a better platform for collaborative brainstorming but separate interviews offered more flexibility and also facilitated more confidential conversations. Three of the largest DMS600 customers were asked to participate in the interviews. The three customers are all large, rural DSOs according to the classifications described in chapter 2.1. Only rural DSOs were chosen for the interviews, since their networks are more prone to faults and therefore development of fault management is usually of greater interest to them than urban DSOs. The participating DSOs are presented in Figure 19 below.

- *PKS Sähkönsiirto Oy*, highlighted in red
- *Savon Voima Verkko Oy*, highlighted in yellow
- *Järvi-Suomen Energia Oy*, highlighted in blue

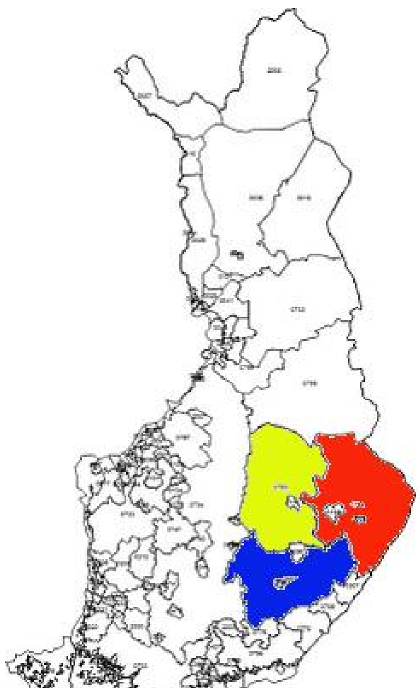

Figure 19. *Interviewed DMS600 customers and their geographical positioning. (Adapted from [78])*

Multiple DSO representatives were present in each interview, consisting mainly of operations personnel. At least one of the representatives in each interview had solid experience in working as an NCC operator. A semi-structured interview method was used to carry out the interviews. The participants were provided with a preliminary questionnaire in advance, containing the main themes and a basic structure for the interview. This questionnaire is available in Appendix A. However, other fault management-related topics were also discussed and the interview consisted mainly of open discussion. Hence, the ideas and requirements described by other DSOs' representatives were also discussed with the later interviewed representatives. The interviews and their results are presented in a chronological order in this chapter. An average duration for an interview was roughly 3 hours and the interviews were recorded and transcribed for later analysis.

One of the objectives of this thesis was also to describe the fault management processes of the DSOs and therefore they were also discussed in the interviews and are described in the following chapters. It was assumed that the DSOs would have at least three different modes of operation for different fault situations; one for single fault situation another for multiple fault situation and a third for major power disruption. It was also assumed that the requirements and needs regarding fault management support functions in DMS600 WS would be somewhat different in different modes of operation. Therefore, the questionnaire was structured based on these assumptions. The differences in the fault management process in each mode and also the reasons behind the transition between different modes were also discussed. In addition, the DSOs' representatives were asked to briefly evaluate the validity of the simulations and conclusions presented in chapter 6, based on their expertise. The DSO feedback regarding the simulations is presented in chapter 7.1. Each DSO and their fault management processes and development requirements and ideas are depicted in the further chapters. Finally, chapter 7.5 summarizes the gathered development ideas and requirements.

7.1 DSO Feedback regarding the simulations

The results of the simulations were presented to the representatives of the DSOs prior to the actual interviews. The representatives had extensive knowledge of their networks and also experience in using DMS600 WS and therefore they were asked to evaluate the validity of the results and conclusions based on their expertise.

All DSOs agreed that calculated fault locations are rarely available and the results of the fault location simulations are therefore conclusive. According to them, clear majority of the actual fault locations are added to the fault report, even if there are multiple fault locations along the same feeder. Therefore, it is likely that most of the incorrect fault locations found in this study were a result of DMS600 WS miscalculation rather than incorrect or inadequate fault location data. [79], [80], [81] However, when an operator is overburdened, during e.g. a major power disruption, it is possible that some fault locations have not been added to the fault reports. It was also pointed out that the percentages of short-circuit faults and earth faults (e.g. 87.6 % and 12.3 % for DSO 1) are likely false. [79] It is likely that this results from a Fault Service module configuration issue, where short-circuit has been defined as the default fault type that will be set to all faults if fault type information is not received from the relay. There are also several different schemas for different types of relays that are used to interpret the fault data correctly for DMS600 WS. It is possible that these schemas are either incorrect or missing for some relays and therefore the fault data in the DMS database may be at least partially false or incomplete. Another reason for missing fault data is that DMS600 WS rejects some information if it has not been received when a fault is established in the system (e.g. when a fault is written to the database). For example a relay may have different update intervals for different types of information. Typically state information is critical and is therefore transmitted spontaneously within a few milliseconds to DMS600 WS. Other information, e.g. fault current measurements and fault types may be updated only periodically. Similar delays may also exist in substation RTUs, which further increase the total delay. Even if this information is transmitted to the DMS afterwards, it will not be written to the database once the fault has been established and is therefore rejected.

The used estimations for the operator's isolation durations in different situations were generally considered plausible. [79], [80], [81] However, it was pointed out that the Rauli-storm, which was used as an example of a major power disruption in this thesis, was not the best choice to be used as a worst scenario. According to [79], the situation was not very severe for a major power disruption. Using a more severe case in the study would have likely resulted in higher calculated benefits due to greater difference in the isolation durations. It was also pointed out that it is difficult to generalize the isolation durations as the situations differ widely and e.g. the starting time affects the level of readiness in each situation. [81] In addition, there were differing opinions regarding the estimated difference in the isolation durations during nighttime and office hours. While some considered the 8-minute difference as somewhat overestimated, others estimated that the actual difference could be even greater. [80], [81]

While evaluation of the presented savings in KAH-value per fault proved difficult for the DSO representatives, the projected annual KAH-savings with the current system were generally considered insignificant. [79], [80] The annual KAH-costs for a large rural DSO are typically millions of euros and the projected savings with the current system account for less than a percent of this total. [79] It was also pointed out that to facilitate a more thorough evaluation, the fault cases would have had to be classified more specifically, e.g. based on the affected area (town-plan area/not town plan area). The used simplification where the load is evenly distributed along the feeder rarely applies in reality. [80]

7.2 PKS Sähkönsiirto Oy

PKS Sähkönsiirto Oy is a subsidiary of Pohjois-Karjalan Sähkö Oy, which is the parent company of the PKS Group. Other subsidiaries are Enerke Oy, Kuurnan Voima Oy and SLT-Consults Oy, focusing on technical services and energy production and sales. PKS

Sähkönsiirto Oy (later PKS) is responsible for providing distribution network services in Eastern Finland, mostly in the North Karelia region. [82] The operating area is large, covering over 25 000 km² in roughly 20 municipalities. [83] The operating area of PKS is presented in Figure 20.

Figure 20. *The operating area of PKS Sähkönsiirto Oy. [82]*

PKS operates a distribution network of approximately 21 000 km, providing electricity for roughly 86 000 customers. [82] Approximately 9800 km of the total network length is MV-network and the rest is LV-network. In addition, PKS also operates approximately 250 km of 110 kV and 60 km of 45 kV regional networks. [8] The North Karelia region is highly forested, with over 85 % of the land area being covered by forests. [84] This makes the network very prone to faults, since the cabling rate of the network is also low (less than 4 % for MV-network). [8]

There are 36 primary substations and approximately 220 feeders. The level of automation in the network is somewhat low; there are around 700 RCDs in roughly 400 RCD-stations, which means that, on average, there are around 7 RCDs per 100 km of MV-network. However, the amount of RCDs is increasing constantly and new sectionalizing circuit breakers (SCBs) are also being installed. About 20 remote-readable fault detectors have been installed into the network but the reliability of the devices and the used communication solution has been found insufficient. Due to this, there are currently no plans to increase the amount of fault detectors. In addition, fault detectors previously had no value in the calculated net present value of the network, which has also affected the decision to discontinue their installations. [79] However, fault detectors for cabled networks are now included in the net present value for the next two regulatory periods. [85] The future strategy to achieving weatherproof network in the beginning and middle sections of feeders utilizes cabled network in urban areas and elsewhere the overhead lines are placed alongside roads and the 1 kV distribution system is used. The end parts will be sectionalized by SCBs to prevent them from causing outages to the weatherproof sections. [79]

The main IT systems integrated with DMS600 in PKS environment are ABB's MicroSCADA Pro SYS600 (later MicroSCADA) and Power Grid NIS (later PG) by Tieto Oyj. In addition, Tieto Care Center (later CaCe) work management system is integrated with DMS600 to enable e.g. the flow of LV-fault reports from CaCe to DMS600. Unlike some DSOs that have acquired communication solutions from external provider, PKS uses and maintains its own radio communication network for field communication. This applies for both RCDs/SCBs and primary substation communication.

7.2.1 Fault management at PKS

Supervision of the PKS network has been concentrated to one NCC, located in Joensuu, North Karelia. In a normal situation, the NCC is manned from 06:00 to 22:00. During the office hours (08:00-16:00), there are two operators on duty and in the evening (16:00-22:00) the supervision is handled by a single operator. During nighttime (22:00-06:00), the operator on duty is on-call but is based at home. If control actions are required from the operator, they are handled with a laptop PC, using virtual private network (VPN). The responsibility over the network is not shared (e.g. geographically) in a normal situation. Instead, both operators are responsible for the whole network. The personnel working in the NCC are not full-time operators and hence carry out operator duties along with their main responsibilities, typically doing a couple of NCC shifts per month. [79]

In case of an LV-fault, the fault management process is initiated by an alarm from AMR device or by a task from the customer service, based on a disturbance call from the customer. Typically a remote query is then sent to all AMR devices in the suspected faulted LV-network. This provides the operator with information on whether there is an actual fault in the LV-network or not. If necessary, the operator will contact the customer directly to ask for further information or to provide instructions. If an actual fault is detected, the operator sends a work order to the responsible contractor via CaCe, who then dispatches a field crew to repair the fault. After repairing the fault, the field crew fills in the LV-fault report to CaCe with mobile PGField-device. The fault report then flows to DMS600 WS, where it is checked by the operator. [79]

The MV-fault management process is normally initiated by MicroSCADA alarm, resulting from a circuit breaker trip. This also causes an audible alarm sound to be played. After this, the operator begins to analyze the situation, based on his/her expertise and the information available from IT-systems. Normally DMS600 WS establishes the fault automatically based on the information received from MicroSCADA but sometimes the fault has to be created manually, if the fault is not rapidly established. This is necessary to get the customer notification working (e.g. the web outage map and SMS-messages), which is considered essential at PKS. The SMS messages are sent to customers who are experiencing an outage 5 minutes after the fault has been established in DMS600 WS and at the same time the fault is updated to the web outage map on PKS website. After the fault has been established in the system, the operator begins the isolation process. The fault location information is utilized if it is available, however this is rarely the case. The operator begins the isolation with RCDs, utilizing both bisection and zone by zone rolling methods. The control-dialogs for RCDs are opened straight from DMS600 WS interface, which facilitates the isolation process. However, sometimes the dialog does not work correctly and instead the device has to be operated from MicroSCADA, which requires additional work. Although it is possible to control feeder circuit breakers through DMS600 WS, they are instead controlled from MicroSCADA. For this reason, the MicroSCADA process display interface is typically kept open continuously during the isolation process. After the remote isolation has been completed, the operator contacts the field crew and guides it to the faulted area, where the field crew begins the manual isolation according to the operator's instructions. The field crew then repairs the fault and restores supply for the rest of the customers. The field crew also provides the operator with further information regarding the fault, which is added to the fault report by the operator. An SMS-message is also sent to the restored customers, confirming that the fault has been repaired. [79]

At PKS, a multiple fault situation is typically considered when there are around 5–10 simultaneous MV-faults. This results in additional operators being called to duty. This is however affected by the starting interval of the faults. For example if 10 faults start within a few minutes, the 1–2 operators that are normally on duty are unable to effectively manage them but if the starting interval is e.g. 15 minutes, the operators on duty can handle the situation without additional resources. When additional resources are called to work, the decision is made by the operator on duty, who has the best understanding of the ongoing situation and the trend. It is particularly difficult if a multiple fault situation occurs during nighttime, when the operator has to work with a single laptop PC and is unable to use multiple systems and interfaces simultaneously, since multiple display devices are not available. Due to this, additional resources have to be called in for a situation that could be handled by a single operator in the NCC. It is estimated that a single operator can handle even 10 faults in the NCC but probably less than half of that at home. Except for the possible additional resources, the actual fault management process and the responsibilities still correspond to the single fault situation. [79]

Formally a major power disruption has been defined as a situation where at least 25 fault are encountered within a day. Again, the starting intervals of the faults greatly affect the severity of the situation. The decision to shift the organization into a major power disruption state is again made by the operator(s) on duty. However, typically the organizational readiness is increased gradually when the situation develops, utilizing e.g. weather forecasts in the evaluation. At PKS, a specific major power disruption organization has been created to increase the effectiveness of fault management in severe situations. The organization has predefined roles for the personnel to facilitate the organizational shift to a major power disruption state. Unlike in previous situations, the operator roles are divided into two categories; operators handling only remote isolations and operators guiding the field crews to handle manual isolations and repairs. There are currently 6 “fixed” workstations available for network operation and they are typically all used in a major power disruption. Additionally, it is also possible to use laptop PCs, however the fixed workstations are usually sufficient as there is a limited number of qualified operators available. A contractor’s representative is also invited to the NCC to manage the field resources. PKS mainly uses a single contractor and therefore only one representative is typically present. During a major power disruption, the progress of the fault management process differs from the previous situations. All remote isolations are carried out by a certain operator who then passes the fault on to another operator. This operator requests resources from the contractor’s representative, who gathers them for the operator to use. The operator then guides the field crews under his/her command to handle the manual isolations and repairs, using a group call system. All switching operations must be approved by the NCC and since there is a limited number of operators available, it is typical that the field crews have to wait for permission to carry out the manual switchings. The fault state-functionality of DMS600 WS is utilized to monitor the fault states while they are being managed by multiple operators in different stages. The field group –field is also used to keep track of the field crews dispatched to a fault. The fault reporting of major power disruptions is typically done only after the situation is over. In some cases the reporting may be started a week after the actual event. The faults are also not necessarily reported by the personnel who handled them during the initial situation. Due to these reasons, the accuracy of the information in the fault reports is often not as accurate as in e.g. single fault situation. [79]

7.2.2 Development ideas and requirements

In addition to the DSO-specific fault management description, development ideas and requirements were also gathered during the visits. The basic idea was to identify development needs in each phase of the general fault management process, depicted in chapter 4.3 and Figure 9. At PKS, most of the needs concerned fault isolation, field crew management and reporting. The gathered development ideas and requirements are discussed further below.

At PKS, the Fault Service module is configured to create the fault package instantly after information of a circuit breaker trip has been received. This enables fast customer notification but fault current data is ignored if it is unavailable once the fault package is created. This naturally results in lower percentage of faults being located. Therefore, the Fault Service module should be modified to allow data supplementation during fault management, after the initial fault package has been created. This would provide the operator with more information about possible fault locations and the feasibility of the current automatic fault isolation and restoration function would also be improved. To provide the operator with more information on possible fault locations, it would also be helpful if the fault locations transferred from other systems were automatically linked to corresponding faults in DMS600 WS. Currently, these fault locations appear as "findings" and have to be looked up separately. [79]

A need for a more feasible automatic fault isolation and restoration, utilizing automatic experimental switchings was identified. Automatic experimental switchings were not considered an electrical safety risk as the interviewees saw no significant difference in whether the switchings are carried out automatically by DMS or manually by an operator. Therefore there were no objections to utilizing e.g. automatic zone by zone rolling method in fault isolation. However, the operator should have a kill switch available to abort the automatic isolation if he/she considers it necessary. Also, a tool for prioritizing faults should be available in DMS600 WS. PKS currently utilizes a separate application for fault prioritization but the interviewees agreed that this kind of function should be available in DMS to reduce the need to use multiple different applications and interfaces during fault management. At least the KAH-value and standard compensations should be considered in the prioritization and a visual, map-based interface for the tool was seen feasible. In addition, line sections should also be visualizable, based on environmental factors (e.g. highlighting of tree-safe/wooded line sections). The operator could utilize this information to infer the most probable fault locations. [79]

During the interview, it was pointed out that, especially during a major power disruption, DSOs often have multiple different types of field crews operating in the field. Some field crews are fully equipped for repair work while others may only handle manual isolations without carrying any equipment. In addition, there are often lumberjacks and forestry machines involved in the fault management process. These crews should be classifiable to different categories and visualized with a different symbol on the map. This would allow the operator to dispatch each crew to the correct location by only using the geographic interface of DMS600 WS. The same function could also be used to track field crews doing regular line section clearing. At PKS, the "field crew"-form in the fault management interface is currently used to keep track of the field crew dispatched to a certain fault. This was not considered very practical, since it is necessary to type the name of the field crew manually for every fault. It should be possible to add a field crew from the field crew management interface to a certain fault in the fault management interface, eliminating the need to manually type field crew names. Currently the fault management interface and the field crew management interface are not integrated in any way. [79]

As was explained in the previous chapter, fault reporting of major power disruptions is often initiated days after the actual event, which often results in less accurate information and takes a considerable amount of time. According to the interview, an operator may have some free time in certain phases of fault management and this free time could be used to report ongoing faults to the greatest extent possible. This would improve the accuracy of the fault reports as the information is still fresh in the operator's mind and the need to use paper notes would also be reduced. In addition, workload could be reduced if at least some of the additional information (e.g. interruption type and fault reason) could be filled in automatically for a certain group of faults that are all related to the same major power disruption. However, information filled in manually by an operator may not be overwritten as there may be cases where the additional information is used in determining the refund liability of e.g. appliance damage. According to the interviewees, there are also some cases where the outage areas automatically included in the fault report are incorrect. Therefore all outage areas have to be checked manually, which takes time. To speed up this process, a visual map-based presentation of all outage areas and their corresponding outage times (e.g. in different colors) was considered helpful. Additionally, automatic comparison of the AMR data and the outage times in the DMS database would help the operator in finding the incorrect fault reports. If the reports are not carefully reviewed, it is possible that, for example, an operator gets a double payment for a single fault as the transaction in HeadPower WMS is dependent on DMS acknowledgment. This is possible when all unsupplied customers are not correctly linked to a fault and the operator has to manually create a second fault for the same feeder to ensure customer notification for all unsupplied customers. If both of these faults are later acknowledged in DMS during fault reporting, the contractor will get payment for both, although the other one was not an actual fault. [79]

As indicated previously, customer notification plays an important role at PKS, since it has been found to decrease unnecessary disturbance calls significantly. According to the interviewees, the Energy Authority has also recently shown growing interest in DSOs' customer notification performance. Therefore a tool for monitoring the status of SMS notification is needed. Currently the web outage map is used to track the status of the SMS messages, as the Outage Info Sender handles both web and SMS notification and hence, if the outage shows up on the outage map, the SMS messages have also been sent. However a more practical tool for monitoring the state of SMS notification would be helpful. Finally, PKS has also had an issue when loading LV-networks in DMS600 WS. According to the interviewees, it may sometimes take over a minute to load a single LV-network. This problem is apparently caused by the current configuration, where the LV-networks are requested and loaded separately from the PG server. The problem should be fixed when the successor of PG is deployed and the LV-networks are available at the local server. [79]

7.3 Savon Voima Verkko Oy

Savon Voima Verkko Oy is one of the two subsidiaries of Savon Voima Oyj. The other subsidiary is Savon Voima Salkunhallinta Oy, which provides financial services in the energy sector. Together, they form the Savon Voima Group. Savon Voima Verkko Oy (later SVV) delivers electricity for over 117 000 households and businesses, mostly in the Northern Savonia region. [86], [87] The operating area of SVV is presented in Figure 21.

Figure 21. *The operating area of Savon Voima Verkko Oy. [87]*

The total length of SVV distribution network is almost 27 000 km. About 11 700 km of this is MV-network and the rest is LV-network. SVV also operates roughly 500 km of 110 kV regional network. [87], [8] Like with PKS, the operating area is large and the Northern Savonia region is also highly forested and therefore the operational environment is very similar to that of PKS. [84] The cabling rate of 6.7 % in the MV-network is highest among the three interviewed DSOs. However, the network still mostly consists of overhead lines and is nonetheless prone to faults. [8]

SVV operates 40 primary substations with over 300 feeders. There are about 1900 RCDs, roughly 16 per 100 km of MV-network, which is the highest ratio among the interviewed DSOs. This amount is also increasing constantly, due to significant investments in the network. A few dozen fault indicators have also been installed into the cabled MV-network and their installations will continue in the future. Currently fault indicators are also being considered for overhead distribution network, but no decision has yet been made. [8], [80]

The main IT-systems integrated with DMS600 at SVV are MicroSCADA Pro SYS600 (MicroSCADA) and Tieto PowerGrid NIS (PG). Therefore, from a system point of view, the environment is similar to that of PKS. In addition, SVV has co-developed a situational awareness system GridWise with Tieto that is also used to handle WMS functionalities. [88], [80] SVV operates its own WiMAX network as a primary field communication solution and in the future, LTE mobile networks are used as an auxiliary solution. [89]

7.3.1 Fault management at SVV

Network supervision is handled from a concentrated NCC, located in Siilinjärvi, Northern Savonia. The NCC is normally manned during 6:45–22:15 and a single operator is responsible for the whole operating area in a normal situation. In the nighttime (22:15-6:45), the operator on duty is based at home and any required control actions are performed remotely with a laptop PC, using VPN connection. [80]

The NCC operators take no part in the LV-fault management process if the fault is reported by a customer via phone. In this case, a separate fault service team will handle the process. The fault service team personnel have no access to DMS and instead the AMR queries are performed from the MRS. The NCC is involved in LV-fault management only if the fault is detected from an AMR alarm. In this case, the operator performs the AMR queries to determine the origin of the fault and the extent of the situation. The operator may also be in contact with the customer and give further instructions. If a fault is determined, a work order is sent to the contractor via GridWise and a field crew is dispatched to repair the fault. The field crew is normally allowed to carry out the LV-switching operations independently but in difficult cases, instructions are given by the NCC. The field crew is responsible for reporting the fault via GridWise, from which it is transferred to DMS database. [80]

MV-fault management process is initiated by a MicroSCADA alarm. Unlike at PKS, there is no configured time limit for the creation of the fault package at SVV and fault management is not initiated in DMS600 WS until fault current measurement data has been received. This results in more faults being located, since measurement data is not rejected but delays the opening of the fault management interface and customer notification. The delays are also partly caused by the old SCIL-API interface that is still used. After the fault management interface has opened in DMS600 WS, SMS-messages are sent to unsupplied customers and the operator begins the isolation process, utilizing experimental switchings. Despite the configuration difference, the fault location is still too rarely available and therefore no significant advantage is gained from the functionality. In a normal situation, the operator sends a work order to the contractor after the fault has been isolated and a field crew is then dispatched to repair the fault. Hence, the procedure corresponds to that of an LV-fault. After the fault has been repaired, customers receive SMS-messages confirming the restoration of supply. The fault is then reported in DMS600 WS by the operator who handled the fault. [80]

There is no formal definition or state of readiness for a multiple fault situation at SVV. According to the interviewees, a single operator can handle even 10–20 active faults without assistance. However, during office hours, it is easy to call another operator to assist in managing the faults, if deemed necessary. Outside office hours, assistance is usually not requested in a multiple fault situation unless absolutely necessary. The progress of the fault management process corresponds to the normal situation, with the exception that the operator has to start prioritizing the fault management actions. [80]

A formal definition for a major power disruption at SVV is 10 faults per region within 24 hours. The operating area of SVV consists of 4 regions and therefore a situation with 40 faults in the whole operating area is considered a major power disruption. This initiates the major power disruption organization. The aforementioned definition is, however, formal and it is possible that the major power disruption organization is used also in less severe situations. At SVV, the decision to shift the organization to a major power disruption state is made by the operations manager or, in his/her absence, the operations engineer on duty. In addition to the number of active faults, weather forecasts and the situation in the operating areas of neighboring DSOs are considered, when evaluating the need to shift the organization into the major power disruption state. There are 4 workstations in the NCC but it is also possible to operate the network from other workstations. However, at best there are 10 qualified operators available in a major power disruption. In the field, there are often forestry machines and lumberjacks working together with the contractors' field crews. In addition, there are also SVV's own personnel who only carry out manual isolations and do not participate in the repair work. Like at PKS, the operators' responsibilities change in a major power disruption. At SVV, there are three different types of operators. First, there are operators who only handle remote isolations and then pass the fault on for manual isolation. Then there are operators who only guide SVV's own personnel to carry out the manual isolations. These operators give the permissions to operate the manual disconnectors but leave the faults unrepaired after they have been isolated manually. Finally, the fault is repaired under the command of the third operator who guides the contractors' field crews to handle the repair work. In the NCC, there is also a person who leads the fault management and allocates the resources (field crews) for each fault. There may also be contractors' representatives present to handle the communication between the NCC and the local contractor foremen. During a major power disruption, work orders are not sent via GridWise but are instead given via phone. At SVV, separate MS Excel and MS OneNote documents are used to keep track of the field crews dispatched to faults. The operators are responsible for reporting the faults after the situation is over. This might be done days after the initial situation and results in similar difficulties as in the case of PKS. [80]

7.3.2 Development ideas and requirements

At SVV, most of the development requirements regarded fault isolation and field crew management. Especially tools for prioritization were considered necessary. A more feasible automatic fault isolation and restoration was also seen important. Some of the requirements and ideas were similar to those of PKS, however, differing opinions were also presented. The gathered development ideas and requirements are reviewed more thoroughly in the following paragraphs.

As was explained earlier, there is no time limit set for the fault package creation and the fault management is not initiated until the fault current measurement data has been received. This increases the amount of located faults but results in customer notification delays. The problem is similar to what was discussed previously at PKS, where the fault current data is rejected to speed up customer notification. At SVV, however, the configuration is different and instead the fault current data is received but customer notification is delayed. In any case, the previously discussed fault data supplementation solution would also benefit SVV. [80]

The interviewees at SVV did not consider automatic experimental switchings as an electrical safety risk and automatic fault isolation and restoration was deemed necessary. However, several requirements for the implementation of automatic fault isolation and restoration were presented. According to the interviewees, the system should be able to manage multiple faults simultaneously and also handle situations where a new fault occurs on a partly isolated feeder. Currently, DMS600 WS does not create a new fault if there is already an active fault in the same feeder. Therefore, e.g. the current automatic fault isolation and restoration function would not be able to manage such a situation. The system should also primarily utilize fault location information and only utilize experimental switching methods if fault location information is not available. In addition, at SVV, the fault indicators keep the indication information for about 10 minutes before resetting and therefore, in the case of a new fault on the same feeder, the fault indication may not be reliable. This should be taken into consideration when implementing a new fault isolation and restoration function. [80]

Fault prioritization was considered highly important in all fault situations and in various phases of the fault management process. However, the prioritization tool should also present the critical areas as a prioritized list since a map-based visualization was considered possibly confusing in a major power disruption situation. The map view and the list should be integrated so that it is possible to locate an area from the map by using the list. According to the interviewees, at least four factors should be considered in the prioritization; the KAH-costs, standard compensations, critical customers and outage duration limits defined by the Electricity Market Act. The user should also be able to stress each factor at his/her own discretion and the level of visualization should be smoothly configurable. A feeder level visualization was considered more useful in a major power disruption but a disconnector zone based visualization could be used when there are only a few faults. In addition, if a new fault has a very high priority, even an audible alarm could be played to ensure that the operator immediately responds to the situation. [80]

To facilitate SVV's fault management process, where multiple operators participate in handling each fault, an effective function to monitor the states of the ongoing faults would be needed. Currently it is possible to manually update the fault state (e.g. isolated by remote control or isolated by work group) from the fault management interface and this function is also used to update the fault state displayed on the web outage map. However, it requires additional work from the operator and an automatic fault state identification and update would leave the operator more time to concentrate on handling the actual fault. In addition, the system could also notify the operator if e.g. the fault has not been completely isolated by remote control. A similar state monitoring function for the field crews was also considered helpful to know whether a field crew is vacant or has been dispatched to a work site. Again, the interviewees considered that an automatic update would reduce the additional work needed but also recognized that the information would have to come from the field crew. This, however, would require additional equipment and changes to the whole fault management process. In total, an integration between the field crew and fault management functions was considered necessary. For example, it should be possible to add a field crew from the field crew management interface to a fault in the fault management interface. The same requirement was also presented previously at PKS. In addition, an idea about sending a prioritized work order list to the field crews, was also thrown out. The list would contain the next work sites for the field crews, which would reduce the phone conversations with the NCC. However, no practical way to implement this was presented. [80]

Unlike at PKS, fault reporting during fault management was not considered necessary. On the contrary, it was even considered a hindrance for effective fault management. According to the interviewees, the operator has no time for fault reporting during fault management in a major power disruption. The automatic reporting tool, however, was considered feasible but the information filled in manually should never be overwritten. Hence, these requirements corresponded to the ones presented previously at PKS.

As was previously described, the fault state displayed on the web outage map is currently updated manually from the fault management interface and the operator's manual work could be reduced if this was done automatically by the system. An idea was also thrown out, regarding a functionality to choose the customers to whom the fault state is updated. For example, certain LV-networks could be selected from the map to provide more accurate estimations of the repair durations and information about the ongoing repair work. Currently, at SVV, DMS600 WS should automatically set a default duration of 4 hours for all faults, but in some cases the duration has not been set and it has to be done manually. In addition, the default time should be configurable during fault management as new 4 hours are added if the fault has not been repaired during the first 4 hours. According to the interviewees, customers become frustrated if the initial durations are not accurate and the duration is increased constantly. Therefore, the customers are often more willing to accept a longer, accurate estimation than initially shorter estimations that are constantly prolonged. [80]

Other requirements that came up during the interviews regarded the AMR-functionalities and DMS notes. DMS notes should be categorizable into different classes and different types of notes should have a different symbol on the map. Among other things, DMS notes are used to denote fault locations and field crew locations and when there are dozens of notes having the same symbol, it becomes difficult to find the information needed in fault management. Therefore, it should be possible to link these notes to e.g. certain faults. Regarding LV-fault management, certain AMR alarms should be blockable to ensure that the more critical ones (e.g. zero sequence faults and conductor breaks) are detected. Currently all AMR alarms are equal in DMS600 WS, while in reality, for example alarms regarding wrong rotation direction or voltage deviations are not critical during a major power disruption. In addition, function to completely block selected AMR devices should be added. According to the interviewees, SVV has multiple consumption points where the consumption is minimal or the main fuses have been disconnected. In these cases, the AMR alarms are irrelevant and the devices should be blocked. Overall, the interviewees considered that simplicity and user friendliness is highly important. This is especially the case in a major power disruption as there are people using DMS600 WS, who are less experienced in using the system. [80]

7.4 Järvi-Suomen Energia Oy

Järvi-Suomen Energia Oy is a subsidiary of Suur-Savon Sähkö Oy. Together with another subsidiary, Kerienergia Oy, they form the Suur-Savon Sähkö group. The group is involved in energy procurement, production and delivery in the Eastern Finland. The parent company, Suur-Savon Sähkö Oy, owns most of the group’s assets, including the electricity distribution network and the district heat network. The electricity distribution network has been leased to Järvi-Suomen Energia Oy (later JSE), which provides electricity distribution services for over 102 000 customers. JSE operates mainly in the Southern Savonia region, but the operating area extends also partly to Northern Savonia, Central Finland, Päijänne Tavastia, Kymenlaakso and South Karelia regions. [90] The operating area is presented below in Figure 22.

Figure 22. *The operating area of Järvi-Suomen Energia Oy. [90]*

The total length of JSE's distribution network is about 27 000 km. Roughly 8000 km of the total network length is MV-network and 18 500 km is 0.4 kV LV-network. JSE has also developed a 1 kV distribution system, which acts as an extension to the MV-network in rural areas but is still considered an LV-system by the SFS 6002 standard. [91], [69] In addition, JSE operates 430 km of 110 kV regional network. [81], [8] As was the case with the other DSOs, the operating area of JSE is also highly forested, with nearly 90 % of the land area being covered by forests in Southern Savonia. In addition, the network area is heavily divided by inland waters, which further complicates the fault management process. [84, p. 10] The cabling rate of JSE's MV-network is also fairly low, about 5 %. [8] Overall, the low cabling rate in a highly forested area together with numerous island locations and inland waters generate a difficult environment. Of the interviewed DSOs, the environment of JSE is probably the most challenging one.

JSE's distribution network consists of some 260 feeders that are fed by 46 primary substations. Currently, there are about 800 RCDs installed in the network, which gives a rate of roughly 10 RCDs per 100 km of MV-network. The amount of RCDs is also increasing strongly, as about 100 new secondary substations are installed annually and roughly half of them are fitted with at least one RCD. In addition, SCBs are also utilized to create separate protection zones for MV branches, which reduces outages in the main lines. SCBs also increase the net present value of the network considerably more than RCDs. There are currently no fault indicators installed in the network, although there has been some pilot projects in the past. At that time, the reliability of the devices was insufficient and hence they were not utilized further. However, re-deployment of fault indicators has been recently under consideration as the technology has evolved. No investment decision have been made and JSE has currently no interest in pilot projects and is instead looking for a reliable and tested product. Therefore, even if an investment decision was made, it would take years before fault indicators could be widely utilized in fault management. [81]

JSE uses Tieto PowerGrid NIS (PG) integrated with DMS600 but unlike the other interviewed DSOs, the SCADA is a Netcon 3000, developed by Netcontrol. Therefore, from a system point of view, the environment is somewhat different from the other DSOs. The use of a different vendors' SCADA also prevents the use of some DMS600 WS functionalities. Like at PKS, Tieto Care Center (CaCe) is used as a WMS. JSE operates its own radio communication network for field communication. According to the interviewees, this becomes sometimes a bottleneck for putting new RCDs into service as establishing communication between the RTU and SCADA takes time if there is no radio network coverage in the area. [81]

7.4.1 Fault management at JSE

As was the case with the other interviewed DSOs, the network supervision is handled normally from a concentrated NCC, located in Mikkeli, Southern Savonia. However, there is a secondary location in Savonlinna, which is often used for managing faults in that area during a major power disruption. In total, there are 7 workstations available for network supervision, of which 6 are located in the primary NCC in Mikkeli and one in the secondary location in Savonlinna. In a normal situation, one operator handles the supervision tasks for the whole network. The NCC is manned from 06:00 to 22:00 and during nighttime, (22:00-06:00) the operator is based at home and controls are handled with a laptop PC, if necessary. [81]

At JSE, disturbance calls regarding LV-faults are handled by an independent contractor, CallWaves Solutions Finland Oy (later CallWaves). They instructs customers to e.g. check their fuses and also gather further information regarding the situation. CallWaves has no access to DMS or MRS and therefore, if the situation is not solved with the simple instructions provided by the CallWaves representative, the fault is passed on to the NCC. The NCC operator then analyzes the situation by sending queries to the AMR devices of the affected LV-network. Real time queries are currently not supported by all AMR devices and therefore the operator occasionally has to rely on the information gathered by CallWaves. If necessary, the NCC may also contact the customer directly via phone. Some AMR devices also send spontaneous alarms but in each case the fault is confirmed by using a manual query, if possible. After an LV-network has been determined faulty, a contractor's field crew is dispatched to the location by sending a work order via CaCe. The field crew is responsible for reporting the fault after it has been repaired. Finally, the NCC checks the report and archives it accordingly. [81]

As usual, the MV-fault management process is initiated by a SCADA alarm that also causes the fault management interface to open after the fault package has been received. Due to incomplete fault service configuration, fault current information is currently not available from most of the primary substations and the fault location function cannot be utilized. After analyzing the situation, the operator begins the isolation process. The general practice at JSE is to first use the bisection method and then continue with the zone by zone rolling method. Depending on the operator, bisection method may be used multiple times before continuing with zone by zone rolling. This speeds up the process as there are typically numerous remote-controllable switching devices available and the early use of zone by zone rolling would be too slow. Since JSE uses Netcon 3000, the control dialogs cannot be opened directly from the geographical interface of DMS600 WS and therefore a separate schematic view of the area has to be always open in Netcon 3000. Upon receiving the fault package, a work order is also automatically sent to Ca-Ce. The work order includes an estimation of the faulted area (e.g. feeder and some LV-network in the faulted zone) so that the field crew knows approximately where they should be headed. In addition, the operator confirms the work order by calling the contractor. As was the case with the other interviewed DSOs, JSE uses SMS messages and web outage map for customer notification and they are updated upon receiving the fault package. After the field crew has moved to the faulted area, the operator guides them in manual isolations. An operator's permission to operate is required for all MV-switching operations. After the fault has been repaired, normal switching state is restored and the operator reports the fault in DMS600 WS. Information regarding the damages and cause of the fault is received via phone from the field crew. [81]

JSE has multiple different states of readiness for its fault management organization. The yellow and orange states correspond to a multiple fault situation and the red state corresponds to a major power disruption. The decision to shift the organization from one state to another is highly dependent on the weather forecasts. JSE uses a special weather forecast service, provided by the Finnish Meteorological Institute. The service has been designed for alerting DSOs about weather conditions that will likely cause damages in the distribution network. When considering the need to shift the organization to a higher state of readiness, e.g. estimated wind speeds, the duration of the storm and the extent of possible damages are taken into account. The decision to raise the readiness to yellow state requires a mutual decision by two operators on duty. In a yellow state, there are typically 2–3 operators handling the faults. However, it is also possible that 2–3 operators are present but the formal readiness has not been raised. It is worth noting that since 2 operators are required to raise the state to yellow, at least a second operator has to be called to duty before the formal readiness can be raised. In an orange state, there are typically 3–4 operators and raising the state to orange requires a mutual decision by an operator on duty and the operations manager. The general fault management process remains the same in yellow and orange states, only the operating area is divided between the operators. If the situation get more severe, contractors' representatives may be called in to guide the field crews. In this case, the next assignment and location is given to the field crew by the contractor's representative, instead of the operator. [81]

A major power disruption is symbolized by the red state. Raising the readiness to the highest state requires a co-decision of an operator on duty, the operations manager and the chief executive officer. However, the initiative to raise the state always comes from the operations personnel, who typically have the best situational awareness. Like before, the decision is made according to the weather forecast and is not defined by any formal criteria (e.g. amount of faults per day, as was the case with PKS and SVV). Typically at least some preparations for the situation have been initiated before the state is formally raised. All seven workstations are typically manned during a major power disruption and therefore 6 operators are working in the primary NCC and the secondary location in Savonlinna is also utilized. The secondary location acts as an independent NCC in its nearby areas. The general fault management process is the same as in the other states and the main difference is that the fault handling area is smaller for an individual operator. However, the overall responsibility of fault management in a certain area still lies in the hands of a single operator and there are no different operator types, as was the case with PKS and SVV. According to the interviewees, this speeds up the process as the operator is always aware of the previous events in his/her area and there is no need to familiarize him/herself with the situation. This is also considered an important factor in ensuring electrical safety in the field. During a major power disruption, the field crews also always get their next assignment and location from the contractor's representative, instead of the operator. In addition, JSE also has its own personnel in the field isolating the faults manually and they are always guided by the operators. Like at PKS, a group call system is used for communication between the NCC and the field crews. [81]

Other major differences are that resource management and crisis communications groups are set up in a major power disruption situation. The resource management group consists of JSE personnel handling the allocation of resources (field crews) to each operator, according to their needs. The crisis communication group consists of JSE management personnel and outside representatives from e.g. the Finnish Defence Forces, Rescue Department and municipalities. This facilitates two-way communication between the outside parties and the DSO. For example, municipalities can provide information regarding critical home care patients, which the DSO can use to prioritize its fault management actions accordingly. The external organizations in turn receive accurate information regarding e.g. the estimated outage durations in certain areas. The crisis management group is also responsible for informing the media about the situation, which reduces the amount of unnecessary disturbance calls and allows the operations personnel to concentrate on the actual fault management activities. [81]

7.4.2 Development ideas and requirements

As was the case with the other interviewed DSOs, development ideas and requirements were discussed also at JSE. The development needs were mostly related to fault isolation and field crew management and no significant new requirements or ideas came up. However, the results of the discussion are reviewed in the following.

The need for an automatic fault isolation and restoration has been identified at JSE. According to the interviewees, JSE needs a system with high feasibility that does not require any initial data (e.g. fault location data) to begin the isolation. To achieve this, automatic experimental switchings should be allowed. However, if fault location data is available, it should be utilized first to speed up the isolation process. Overall, the interviewees considered that the system should imitate the actions of a human operator. The system should also be able to isolate multiple faults simultaneously but only in separate fault management areas. Therefore it would be necessary to define fault management areas where the system is allowed to operate. This would ensure that the automatic isolation and restoration would not interfere the human operators operating in another area. In addition, the system should be able to disregard inoperable switching devices (e.g. if a communication link cannot be established) and continue the isolation process using the next available device. The interviewees considered that a tool with the aforementioned features would be especially helpful during the beginning phase of a major power disruption, when numerous faults occur simultaneously. Since JSE uses the Netcon 3000, cooperation with Netcontrol would be necessary to implement the tool. An idea of utilizing the current FLIR-interface (Fault Location, Isolation and power Restoration) of Netcon 3000 in the implementation was also discussed. However, this feature has been co-developed with Trimble, specifically for Trimble DMS and therefore both technical and proprietary issues may present an obstacle to this. [81]

A tool for fault prioritization was also considered highly necessary. The interviewees considered that at least KAH-costs and critical customers should be taken into account in the prioritization. The user should be allowed to stress each factor based on his/her judgement and therefore an index-based prioritization could be used. However, a direct presentation of monetary values was also considered clear and easy to understand. According to the interviewees, a map-based visual presentation would be especially helpful and unlike at SVV, a disconnector zone based visualization was not considered confusing, even during a major power disruption. The interviewees at JSE found a visual presentation more beneficial in multiple ways, comparing to the presented list-based view. According to them, a visual presentation will help the operators to develop a stronger intuition about the most important locations and line sections. This will eventually reduce the need to constantly use the prioritization tool. The map-based presentation was also considered helpful for the network planning department in determining the optimal locations for remote-controllable switching devices. Even field crews might benefit from a map-based visualization as they would then have better understanding of where the field resources are being allocated and why. [81]

Unlike with MicroSCADA, it is not possible to open the control dialogs of the switching devices directly from the geographical interface of DMS600 WS when using Netcon 3000. Adding this feature also for Netcon 3000 would reduce the need to have multiple SCADA-windows open during fault management. Although not actually related to fault management, a need to visualize the ongoing maintenance outages on the DMS600 WS geographical interface was also presented. Due to the increasing amount of live-line working, it is necessary to ensure that the operator does not make potentially hazardous switching operations that affect the feeder with the ongoing live-line work. A potential work hazard could be caused by e.g. connecting the live-line work location with a feeder having reclosings on. Additionally the system could also automatically warn the operator when he/she is about to make a potentially hazardous switching but this would require changes mostly to Netcon 3000. Alternatively, the previously described idea about categorizable DMS notes was also considered feasible for marking the ongoing maintenance outages on the map if different symbols for different types of notes were implemented. However, this would require manual work from the operator. In addition, an idea about a tool for simulating the damages and costs caused by a major power disruption was also presented. According to the interviewees, JSE has statistical data of e.g. the damages caused by a storm with certain wind speed and this data could be used by the tool to calculate the damages and e.g. KAH-costs in advance, based on the inputs provided by the user. The idea about this tool, however, was rather vague and the actual implementation had not been considered more thoroughly. [81]

7.5 Summary of the gathered development ideas and requirements

During the interviews, numerous ideas and requirements were presented, some of which were significantly more complex than others. Hence, also significantly more work would be required to implement some of the proposed changes. Of the proposed changes, the more complex ones were the new automatic fault isolation and restoration tool, the fault prioritization tool and the automatic fault reporting tool. The other ideas were mostly smaller additions and changes to some of the current features of the system. Table 12 presents the gathered development ideas and requirements and also visualizes the ones that were considered necessary by multiple DSOs. From this table, it is easy to see which functionalities would provide value for multiple DSOs, according to the insights of the interviewed representatives. The last item in the table is in brackets, because it is not actually related to fault management, which was the topic of this thesis.

Table 12. *Summary of the gathered development ideas and requirements.*

	PKS	SVV	JSE
Fault data supplementation after a fault has been created in DMS600 WS	✓	✓	
Changes to visualization of imported fault locations	✓		
New automatic fault isolation and restoration tool	✓	✓	✓
Fault prioritization tool	✓	✓	✓
Field crew categorization & visualization with different symbols	✓	✓	
Integrating field crew management with fault management	✓	✓	
Automatic/semi-automatic reporting	✓	✓	
Features to enhance fault report checking	✓		
Improvements to customer notification management	✓	✓	
DMS notes categorization & visualization with different symbols		✓	✓
Changes to AMR-device and alarm management		✓	
Ability to open Netcon 3000 control dialogs from DMS600 WS			✓
Major power disruption simulation tool			✓
(Map visualization of maintenance outages)			✓

The new automatic fault isolation and restoration tool and the fault prioritization tool were considered necessary by all three DSOs, as can be seen from Table 12. Other changes and improvements that were mentioned by multiple DSOs were the fault data supplementation, field crew and DMS notes categorization and the ability to visualize them with different symbols and the automatic or semi-automatic fault reporting. Integrating the current fault management and field crew management functions were also mentioned in multiple interviews, along with some improvements to managing customer notification features. Overall, the requirements and needs of PKS and SVV were similar and the ones mentioned by JSE representatives seemed to differ from the two others. One reason for this is that both PKS and SVV have mostly the same IT-systems in use while JSE uses, for example, a different SCADA. Naturally also the DSO representatives present in the interviews have a significant effect on the results. Based on the results of the interviews, some ideas were chosen for more thorough review and they are described further in chapter 8.

8. IMPROVEMENTS TO FAULT MANAGEMENT IN DMS600

As a result of the interviews presented in the previous chapter, numerous development ideas were obtained. After reviewing the results and the workload required, two larger changes were chosen to be more potent for implementation and were therefore chosen for implementation analysis:

- A new fault prioritization tool
- Automatic fault reporting feature

These new functionalities will be reviewed thoroughly in chapters 8.1.1 and 8.1.2. During this thesis, a separate specification document was also created for the aforementioned new features, including e.g. the principles of operation and user interface models. Some of the other important requirements that came up during the interviews will also be reviewed in the latter part of this chapter, but the main focus is on the new functionalities which will be implemented based on the specifications created in this thesis. However, before the implementation of any of the described features may begin, the customers' willingness to pay for them must be confirmed.

8.1 The most potent features for implementation

A tool for fault prioritization was considered helpful and necessary by all interviewed DSOs and therefore it was a clear choice for a closer analysis. The tool could also be implemented by only making changes to DMS600 and no changes to e.g. MicroSCADA were needed. Therefore the tool could be implemented as an independent project, which was another reason why it was chosen for more thorough review and development. The fault prioritization tool is introduced further in chapter 8.1.1.

The other new feature, chosen for a closer review is the automatic fault reporting feature. While automated fault reporting was not directly mentioned by the representatives during the interviews, it was clearly pointed out that fault reporting requires a lot of work after major power disruptions and some tool for reducing the workload is necessary. Hence, an automated fault reporting feature was seen as a suitable solution to the problem. However, during this thesis it was somewhat unclear how completely the automation would be implemented as complete automation of fault reporting would require significant amount of work. Therefore both the completely automated fault reporting feature and a limited version will be discussed in chapter 8.1.2.

8.1.1 The fault prioritization tool

The fault prioritization tool was discussed with all DSO representatives and they all agreed that it would be a useful addition in assisting the operator. During the interviews, several requirements regarding the functionality and usability of the tool were mentioned. Some representatives mentioned only one or two factors that should be taken into account in the prioritization while others named multiple ones. There was also some disagreement about whether the prioritization should be implemented as a visual, map-based view or as a prioritized list. In addition, different requirements for the prioritization level (e.g. feeder/disconnector zone) were presented. To best answer the needs of all DSOs, both map- and list-based interfaces were chosen for the suggested implementation in this thesis and also multiple factors will be available when generating the prioritization order but the user will be able to configure their weight in the prioritization. User will also be able to change the level of prioritization according to each situation. The functionality of the tool will be discussed in greater detail below.

During the customer interviews, four different factors were mentioned when discussing what should be taken into account when prioritizing faults. These were all chosen to be included in the prioritization tool and they are:

- KAH-costs
- Standard compensations
- Critical customers
- The maximum outage durations defined by the Electricity Market Act

Since some of these factors are monetary (KAH-costs and standard compensations) and the others are non-monetary, they cannot be simply summed up. Therefore, a specific prioritization index is needed to represent the priority of each unsupplied area according to the chosen prioritization level. This index is generated by summing up four subindexes representing each factor and weighting them with user-defined coefficients. The subindexes represent the relative importance of each factor in each unsupplied zone in the ongoing fault situation. In other words, the index is used to define the importance of each unsupplied zone in the current situation and not the absolute importance.

To calculate the indexes, some simplifications had to be made since, e.g. the actual standard compensations cannot be calculated in the DMS as the information regarding the annual network service fees of the customers is not available in DMS. Also, since the DSO's objective is to minimize e.g. the KAH-costs and the standard compensations, the growth rate of these factors is often more interesting to the DSO than the accumulated values that have already incurred and can no longer be affected by operator actions. Therefore, the tool primarily simulates the growth rate of these factors, although for the KAH-factor, the user can also configure the tool to use the accumulated KAH-value. The factor for taking the requirements of the Electricity Market Act into account will be generated by using the Distribution Reliability Requirement Classes (DRRC) implemented in the Master's thesis of Lamminmäki [24]. This classification is a DMS600-specific feature that is used to categorize consumption sites according to the requirements of the Electricity Market Act. The DRRC-factor of the prioritization tool will take into account the duration of the outage relative to the corresponding DRRC-limit and the amount of customers in each DRRC-category. Finally, the factor for critical customers will be generated by comparing the unsupplied critical customers of each zone to the total amount of unsupplied critical customers. The critical customers are defined by the importance rating available in DMS600. Importance ratings can be set either for specific customer nodes or whole secondary substations. By default, DMS600 offers 10 importance classes that the DSO may utilize and name according to their needs. Due to this, the fault prioritization tool does not take into account the relative importances of customers having different importance ratings. For example a certain DSO could use rating 10 for hospitals and health centers while another might use rating 5. Since the ratings are DSO-specific, the absolute importance cannot be determined directly from the rating. Due to this, all customers having an importance rating other than the default (1), will be considered as critical in the prioritization. If DSOs would generally use the same ratings for similar customers, the prioritization could be extended to take into account the difference in the importance ratings of customers/secondary substations.

As previously mentioned, a requirement to change the prioritization level was presented by multiple DSO representatives. Therefore three different prioritization levels were chosen for implementation:

- Feeder
- Remote-controlled zone
- Manual disconnector zone

The user will be able to change the prioritization level quickly from a GUI window of the tool. This facilitates the use of the tool in different situations. For example during the first hours of a major power disruption, extensive parts of the network are typically unsupplied and therefore prioritization on a manual disconnector zone level will most likely be somewhat confusing. Instead, the user will likely want to see the prioritization on a feeder or remote-controlled zone level. However, during the last phases of a major power disruption or in a few fault situation, prioritization on a manual disconnector level can be useful when the unsupplied area is more limited.

The selected prioritization will be presented on the map as well as a list. The values of the calculated prioritization indexes, used as a basis for the prioritization, will not be visible to the user. Due to its previously described nature, the specific value of the index in a certain zone are not interesting but their relation to the corresponding indexes of other unsupplied zones is. Therefore the list view will only display a list of zones in a prioritized order according to the chosen level. In the map-based view, the unsupplied network will be colored based on the calculated indexes, similarly to the topological coloring. However, a highlight coloring will be used instead of a separate coloring mode and only the unsupplied areas will be highlighted. Using the highlight coloring, the current switching state can be displayed in the background while utilizing the prioritization tool. Due to the nature of the prioritization index, the coloring will be dynamic, based on fractiles of the highest index in a current situation. Therefore the zone with the highest index will always be displayed in red and the coloring of the other zones will be determined based on fractiles of the highest index. Therefore the coloring can only be used to determine the most important zones in the current situation as at least one area will always be colored in red but the color does not reflect the absolute criticality of that area.

Since the prioritization is dynamic and the absolute criticality of the situation cannot be determined, additional information of the overall situation will be displayed in the outage information window. This information will include easy-to-understand key figures of the overall situation that the operator can use to assess the criticality of the situation and then use the prioritization tool to determine the critical zones in each situation and allocate resources accordingly. The key figures can be e.g. total amount of unsupplied customers, total amount of disconnected power and hourly KAH-growth rate in the network. A concept of the possible implementation is presented in Figure 23.

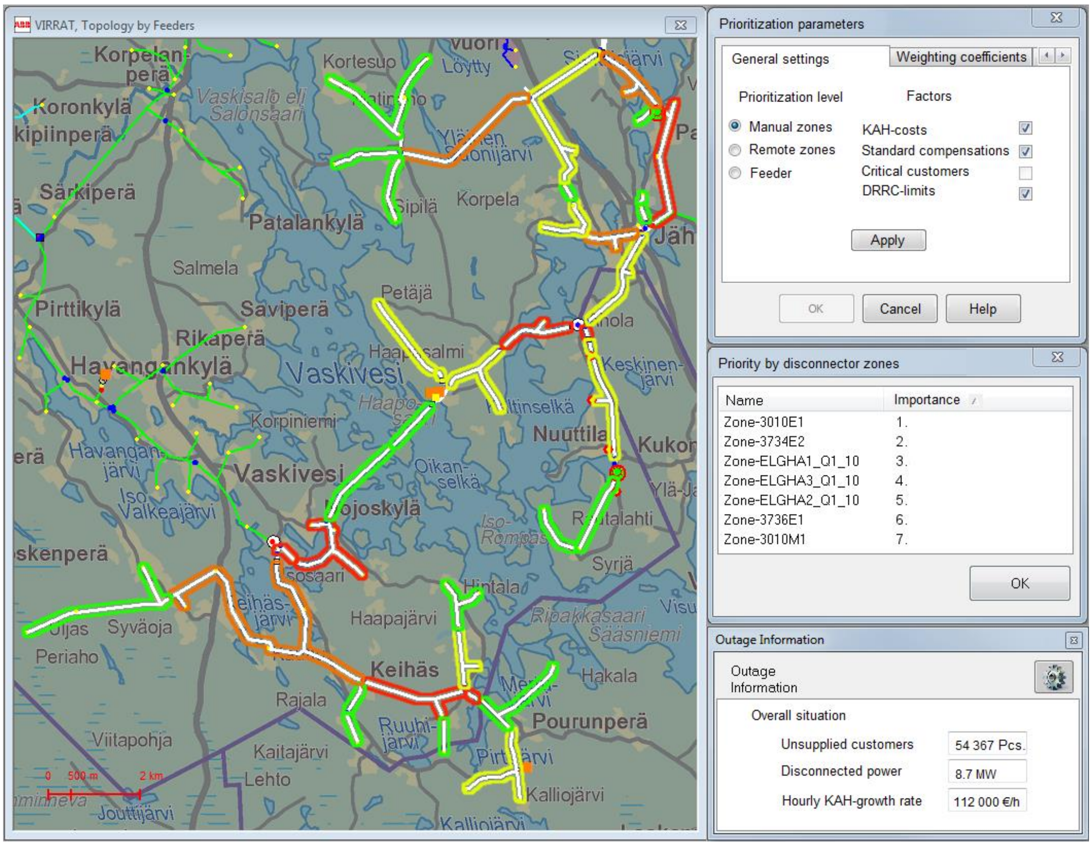

Figure 23. Concept of the interfaces of the new prioritization tool.

The main interfaces needed to use the tool are presented in the concept above. In the network window, the highlight coloring is visible with the topological coloring mode in the background and the list-based view can be seen on the right. The configuration interface is also displayed in the figure, along with the modified outage information window with three key figures of the overall situation visible.

As an external part of the prioritization tool, an additional KAH-coloring mode should also be added. This mode will color the whole network based on the hourly KAH-growth rate of each feeder in the current topological situation. Monetary values will be used in this mode and the coloring limits will be defined by the user as with all other coloring modes.

8.1.2 Automatic fault reporting

Two of the three interviewed DSOs mentioned that fault reporting requires a lot of work, especially after major power disruptions. A number of options to reduce this workload were discussed during the interviews and later when analyzing the results of the interviews at ABB. Both limited and completely automatic fault reporting features were proposed for implementation. However, during further discussions, it was concluded that implementing a completely automated fault reporting would require major changes to DMS600 WS and therefore the DSOs willingness to pay for such a feature must be discussed further with their representatives. During this thesis, it remained unclear which of the two options would eventually be implemented and therefore both options are briefly described in this chapter.

In the completely automated reporting feature, the user will be able to choose multiple repaired but unreported faults from the fault list and report them all at once. This will initiate the simulation mode and DMS600 WS will simulate all the switchings regarding the selected faults. Currently the user has to simulate each fault separately and therefore DMS600 WS constantly switches between state monitoring and simulation states, which slows down the process. The user is also required to intervene by updating and accepting the report for each fault. In the proposed feature, the outage areas will be created automatically for all the selected faults and also the outage durations and other information will be calculated and added to the reports during the process without any involvement required from the user. No significant changes to interfaces are required to implement this feature as the user is only required to select the faults he/she wishes to report and DMS600 WS then handles the process independently.

As was described previously in chapter 5.2.5, most of the information needed to be filled in manually is contained in the “additional data” tab. While some DSOs may not use all the fields in the tab, at least the “Outage reason”, “Fault reason” and “Location of fault” –fields are required by the Finnish Energy. These fields have predefined codes and values according to the outage statistic instructions provided by Finnish Energy

[92] and they are used to compile the annual outage statistics. However, most of the faults occurred during the same major power disruption have same Outage reason (e.g. V1 Unanticipated interruption in own network) and Fault reason (e.g. L1 Wind and Storm). Also the value for the “location of fault” field is most likely “A2 Overhead line network” for majority of the MV-faults. Hence, to reduce the amount of manual work needed, the values for these fields could be copied to all faults occurred during the same major power disruption. A concept of a modified “additional data” tab is presented in Figure 24. In the figure, the fields that contain information that could be replicated to all faults occurred during the same major power disruption are circled in red. In the concept, checkboxes have also been added to allow the user to choose what information will be replicated to the selected faults.

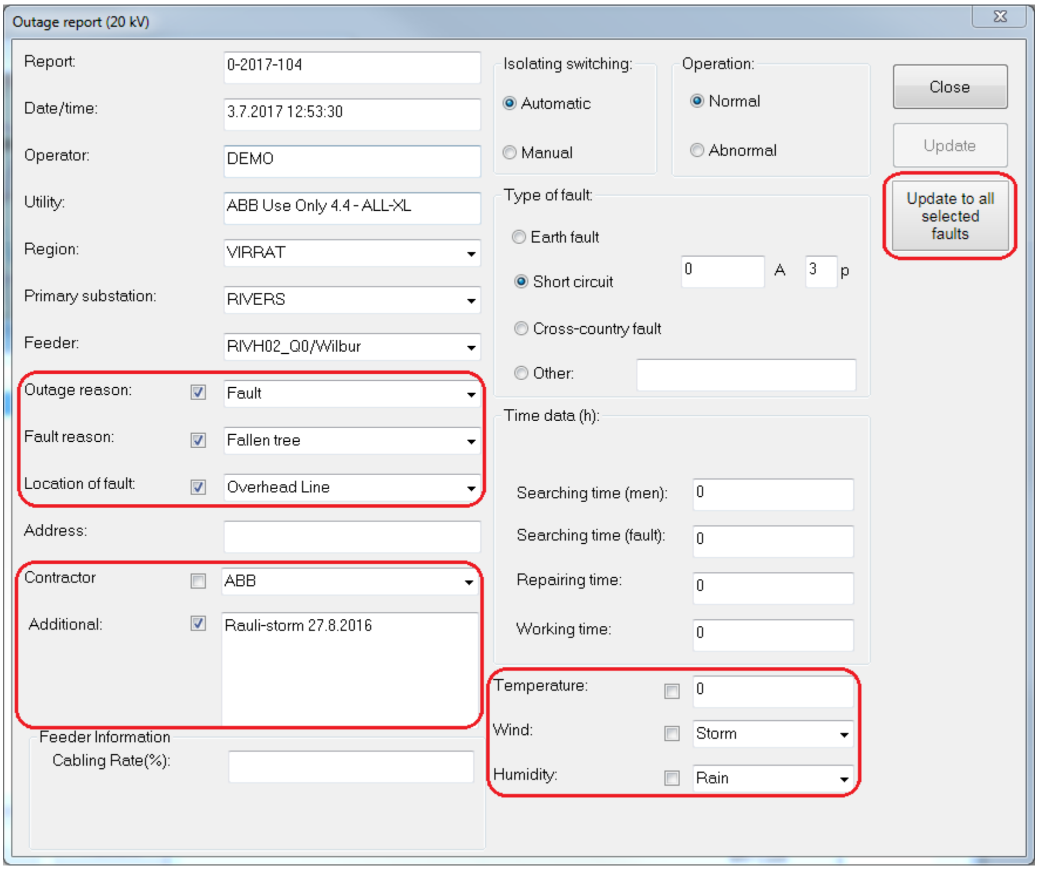

Figure 24. *Concept of a modified “additional data” tab, with the replicable fields circled in red.*

With the implementation of these features, the user would only fill in one “additional data” tab and select the faults for reporting and replication and no further involvement is required. Only the exact fault location would have to be added manually to each fault but this is often done as soon as the actual fault has been found and the fault is still active in DMS. Naturally there are some cases where the replicated information is not accurate and has to be filled in manually and hence, if information has been filled in manually, it may not be overwritten by the replication feature. In the limited version of the automated fault reporting, only the replication feature is included as it requires significantly less work to implement.

8.2 Future developments

In addition to the ideas and requirements that were chosen for a closer review, multiple other viable improvements were discovered during the interviews. The most potential ones for future implementation will be reviewed in this chapter and their features will be described. The descriptions are mostly based on the requirements gathered during the interviews but also some additional ideas will be introduced for consideration and the results of the simulations carried out are reflected in the descriptions.

The most important fault management improvement that was not included in the aforementioned separate specification document is the new automatic fault isolation and restoration. As this feature is a larger upgrade, it will be reviewed separately in chapter 8.2.1. The main difference when comparing this review to the new features described in chapter 8.1 is that no implementation specifications were generated that would e.g. consider exact operation principles, usability and user interface design. Other viable but smaller changes and additions based on the interviews will be reviewed in chapter 8.2.2.

8.2.1 New automatic fault isolation and restoration

The current automatic fault isolation and restoration feature of DMS600 WS is not actively used by any of the current DMS600 customers and in order to facilitate its wider use, it is clear that it must be redesigned. This was also agreed by all the representatives of the interviewed DSOs. All the representatives also identified the need for automatic fault isolation and restoration and this was one of the two larger improvements mentioned in all interviews. However, the requirements gathered during the interviews were not comprehensive enough to create a specification for immediate implementation. Before beginning the implementation of such a large upgrade, further discussions, probably with more than three DMS600 customers, were deemed necessary and this was not possible within the timeline of this thesis. Also, implementation of this feature would not only require changes to DMS600 but also to the SCADA that it is integrated with. Naturally the feature would first be developed for DMS600–MicroSCADA –combinations but the feature was also seen necessary by e.g. JSE and in this case co-development with Netcontrol would be needed. The same applies for all DMS600–external SCADA –combinations. Due to these reasons, the feature was not studied as thoroughly as the previously mentioned ones and no comprehensive specification was created during this thesis. However, some requirements and ideas regarding a new automatic fault isolation and restoration feature are discussed in this chapter.

During the interviews, all representatives agreed that the logic of a new automatic fault isolation and restoration should be based on utilizing experimental switchings. This conclusion is also supported by the simulations carried out; the automatic fault isolation and restoration must not be fully dependent on the fault location function as definite fault locations are rarely available and even then there were notable amount of incorrect locations included in the results. Also, based on the simulation results, changing the logic to restore some of the "likely healthy" –zones would not considerably improve the feasibility of the feature. In addition, according to the interviews, some DSOs have no interest in deploying fault indicators and even while others do, it will take years before reliable and extensive fault indication is available throughout the networks. Thus, to maximize the feasibility of the new feature for all customers, it must be implemented in a way that no initial data is necessarily required to commence the isolation sequence. However, if fault location information is available, it should be utilized as a primary option and in this case, the switching sequence would be planned as it is done currently. Unlike in the current system, the isolation should not be aborted by a circuit breaker trip and instead, the process must be continued by utilizing experimental switchings, like a human operator would do. Incomplete fault location information should also be utilized, e.g. if a fault is not definitely located due to multiple calculated fault locations in the end part of the faulted feeder. In this case, the system should try to restore the beginning and middle parts of the feeder without first applying experimental switchings to them and then continue with the experimental switchings in the end part of the feeder. A very general depiction of the logic is presented in Figure 25.

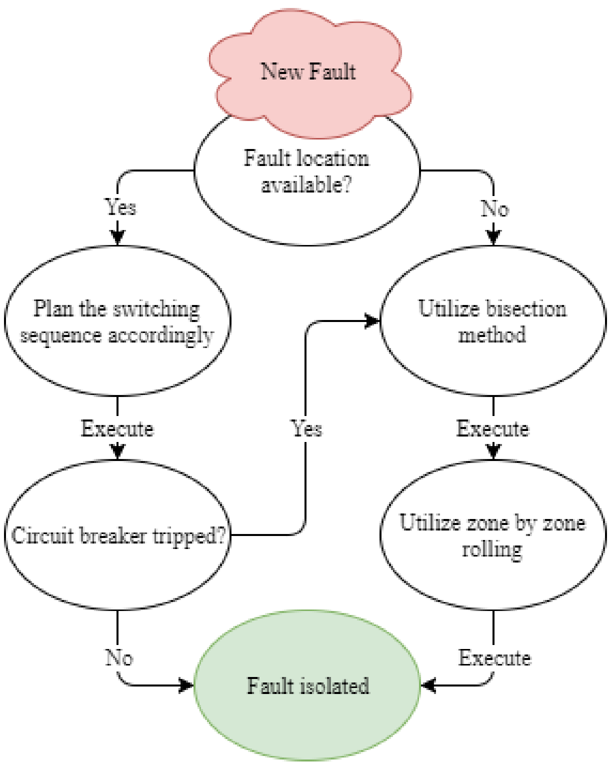

Figure 25. *Example of the new automatic fault isolation and restoration logic.*

Also, if fault location is available and the planned switching sequence is interrupted by a circuit breaker trip, the system should remember what switching operation caused the trip and use this information when continuing the process with the experimental switchings. When using experimental switchings, both bisection and zone by zone rolling methods should be utilized as this speeds up the isolation process, especially when the amount of remote-controllable devices increases constantly.

One of the most important changes when comparing the new automatic fault isolation and restoration to the current one is that it should be able to isolate multiple faults simultaneously. Currently this is not possible and it limits the feasibility of the feature significantly, especially in major power disruptions, when the need for the automation is greatest. However, it should be ensured that the multiple simultaneous isolation processes do not interfere with each other. This could be accomplished by defining smaller operating areas where only one automatic isolation process is allowed at a time.

To maximize the feasibility of the automatic fault isolation and restoration, the system should also be able to isolate a new fault on a feeder already having a partly isolated fault active. This requires changes to the general fault management logic, where only one fault may exist per feeder and therefore a new fault is not created in DMS when a circuit breaker trips on an already faulted feeder. Thus, the system should monitor the already isolated faults/feeders and commence a new isolation process if the feeding circuit breaker is tripped by a new permanent fault. This, however, includes a potential electrical safety risk, if e.g. a field crew is performing manual isolations or repair work in the previously isolated section. To overcome this issue, e.g. the fault state information could be used. For example, if the fault state is “manual isolation in progress” or “repair in progress”, the system could ask confirmation from the operator before commencing the new isolation sequence. In this case, however, the operators would have to be very careful when changing the fault states as the fault state is now mainly used to update the fault state on the web outage map. Alternatively, a confirmation could always be required when the system is about to commence a new isolation sequence on a feeder having an active fault. Another problem that may occur is that the fault indicator data may be false if the new fault appears shortly after the previous one. In this case, the fault indicator data may correspond to the previous situation as the devices may hold the previous state for e.g. 10 minutes before resetting. This, however, would not be a serious problem as the system would be able to continue the process with experimental switchings and only the planned sequence for the false location would fail.

When implementing an automatic fault isolation and restoration feature with experimental switchings allowed, certain safety-related issues have to be considered. To ensure electrical safety in all situations, the system should at least include the following features:

- Option to choose the areas or feeders where the automatic fault isolation and restoration is allowed to operate.
- Automatic checking and reservation of the switching devices included in the automatic isolation process.
- Option to abort the process manually from a separate kill switch.

These features should prevent situations where e.g. operator tries to operate a switching device that is also being used by the automatic fault isolation and restoration. The ability to choose the operational areas would reduce the chances of interference with operator's isolations. The system should also check that the switching devices it is about to use are available. However, a communication problem with a single device should not result in abortion of the process and instead, the next available device should be used. The kill switch will ensure that the operator has the ability to abort the process immediately if he/she sees it necessary.

8.2.2 Other minor changes and additions

In addition to the larger improvements described earlier, there are numerous smaller fault management–related changes and additions that could be implemented. Comparing to the larger improvements, these would require considerably smaller amount of work to implement. However, not all are worthwhile and therefore only a few of the most viable ones are discussed in this chapter and they are:

- Fault data supplementation after a fault has been created in DMS600 WS
- Better integration of fault management and field crew management
- Field crew categorization and visualization with different symbols
- DMS notes categorization and visualization with different symbols

Currently no fault data is added to a fault in DMS600 WS after it has been established. Therefore the system can either be configured to wait until all information has been received, which slows down customer notification or the fault can be created quickly but e.g. fault current measurement data could be missing. Allowing later supplementation of the fault data would ensure both fast customer notification and more complete fault data, which in turn enhances the feasibility of the fault location function.

To allow for a more effective field crew management, integration with the fault management interface is necessary. Currently the fault management only supports a manual text field where the name of the field crew is typed for every fault and the field crews in the field crew management interface are completely separate feature. Instead of the manual text field, the field crew management should be opened from the "Field Group"-button in the fault management interface and e.g. drag and drop could be used to attach field crews to a fault from the list. In addition, the field crew management interface could display the field crews as e.g. "busy" or "free" based on whether they have been attached to a fault or not. This would remove the need to use external tools to keep track of the available field crews and their assignments. According to the interviews, separate MS Excel and MS OneNote documents currently have to be used for this purpose.

As another addition to field crew management, the field crews should be categorizable according to e.g. their capabilities and equipment. There are already some fields in the field crew management interface that could be used for this categorization, such as the type of the vehicle the crew is using. Especially important is to be able to distinguish e.g. lumberjack and forestry machine crews from the actual repair crews. Therefore the different field crew classes should be visualized with different symbols and possibly even filtered to display only the selected classes on the map.

A similar change is needed for the DMS notes that are used to mark a variety of information on the map. Currently there is no way to tell whether a DMS note concerns e.g. contact information for a customer's representative or a possible fault location without reading the note. In total, there may be hundreds, even thousands of notes that are displayed on the map, if selected. During fault management, only minority of these are relevant and therefore a categorization feature is needed. This feature would allow the user to define a certain amount of classes and name them at his/her own discretion. These would then be depicted by different symbols on the map and filtering would also be available to display only the selected class of notes. The feature would likely also prove helpful for other purposes, not only fault management. For example PKS uses the notes to mark locations in need of maintenance and consumption sites with microgeneration, among other things. Visualizing only these notes would be helpful for e.g. switching planning and maintenance planning personnel.

9. CONCLUSIONS

Fault management has traditionally been a key part of the network operation process and despite the significant ongoing investments in distribution networks, it will remain so for at least the next decade. However, DSOs requirements and preferences regarding fault management have changed over time. For example the role of customer notification has become increasingly important in the recent years as both the Energy Authority and decreasing public tolerance toward power outages has put pressure on the DSOs to provide more accurate customer notification services during outages. Also, the increasing amount of network automation available enables better overall control of the network and more data is also remotely available to be utilized in the fault management. The DMS is a key part of distribution automation as it combines and processes the information supplied by multiple sources. During fault situations, the DMS should be optimized to provide the operator with the best possible support in decision-making and therefore the fault management functionalities should comply with the needs of DSOs.

This thesis studied the requirements of Finnish DSOs, regarding fault management in ABB MicroSCADA Pro DMS600 WS by interviewing three largest rural DMS600 customers. Fault simulations were also carried out during the thesis to study the feasibility of the current fault management features of DMS600 WS. Based on the interviews and the results of the simulations, numerous development issues were identified and specifications for the implementation of the most important ones were also created.

The fault simulations focused on the current automatic fault isolation and restoration feature available in DMS600 version 4.4 FP1 HF3. The feasibility of the fault location function was studied and the current isolation and restoration function was tested in an actual environment of a rural DSO. In addition, the monetary benefits achievable from the use of an automatic fault isolation and restoration were evaluated on a general level. According to the simulations, the switching sequences generated by the current automatic fault isolation and restoration are mostly correct and multiple simultaneous faults in the same area do not affect its operation. However, the feature is not utilizable in most cases as it is fully dependent on the availability of the calculated fault location. According to the simulations, fault locations were calculated for less than 14 % of the 2016 faults in the studied network and less than half of these were further definitely and correctly located. The average monetary benefits in terms of KAH-value reduction from the use of automatic fault isolation and restoration were also evaluated in this thesis. Although it proved difficult to provide reliable and accurate estimations, it seemed clear that the current feature provides very little benefits if e.g. extensive fault indication is not available, since the feature cannot be utilized in most cases. However, by changing the logic of the feature, considerable benefits might be available, especially for the DSOs not having 24/7 manned NCC. For example, the average KAH-values for a fault in 2016, calculated with the actual disconnected power, were about 5000 € for DSO 1 and 8000 € for DSO 2. Thus, according to the calculations, roughly 6–8 % KAH-reduction could be achievable in the nighttime, if the NCC is not manned and on average 2–3 % reduction for all faults. Hence, if the automatic fault isolation and restoration could be used for most of the faults, the annual KAH-reduction could be hundreds of thousands of euros for a large, rural DSO as their annual KAH may often exceed 10 million euros.

Although the percentage of located faults gives some idea of the feasibility of the current fault location function, the result is strongly affected by the configuration of the fault service module at the studied DSO. Since most relays are capable of transmitting and measuring the fault current or impedance of short-circuit faults, at least most of the short-circuit faults should be locatable. However it is the configuration of the DMS600 and its components that may limit their availability in the system and this reduces the percentage of located faults. To study the overall feasibility of the function, it would have been better to choose an environment where the configuration allows all fault data to be processed in the DMS. Also, the manually created “customer notification faults” reduced the percentage in this study, but no simple way to filter them from the results was found. The calculated benefits per fault were most likely at least somewhat underestimated in this study as it was assumed that the power consumption is distributed evenly along the feeder. In reality the consumption is usually concentrated on the beginning of the feeder and this area is also often less prone to faults and can therefore be often restored. It is also difficult to calculate the average KAH-reduction for a fault as the amount most likely differs significantly in different fault situations and overall, there are numerous factors that affect the calculations as many assumptions had to be made. However, the simulations were not the main focus of this thesis and therefore simplifications had to be made to keep the topic compact in this thesis. Overall, it seems that thorough analysis of the benefits of an automatic fault isolation and restoration could solely provide a topic for another thesis.

The customer interviews provided numerous development issues, most notably requirements for the new automatic fault isolation and restoration feature and the fault prioritization feature. The general fault management processes of the interviewed customers were also described in this thesis. Although the interviewed DSOs were the three largest DMS600 customers, their requirements and preferences cannot be fully generalized to apply for all Finnish DSOs. The operating areas of the interviewed DSOs were also very similar and were located in the Eastern Finland and therefore a couple of DSOs operating in other parts of the country could have presented at least somewhat different opinions. In addition, the people participating in the interviews always have a strong effect on the results as there are certainly different perspectives inside each company. Also, the order of the interviews most likely had some effect on the results as the DSOs that were interviewed later were presented with some requirements and ideas originally introduced in the previous interviews. Some DSO representatives also seemed better prepared for the interviews than others. However, it was beneficial that at least one person with solid experience in using DMS600 was present in all interviews. Finally, during the interviews, the conversation sometimes tended to focus too much on the DSOs own processes and not on identifying the key development issues in the system, which was the main target of the interviews. Therefore, polite but strict guidance of the discussion could have been beneficial in some situations.

Based on the results of the interviews and simulations, two features were chosen for implementation analysis; a new fault prioritization tool and an automatic fault reporting feature. Specifications for these two upgrades were created during this thesis and also visual concepts of the new user interfaces were presented. However, the implementation of these features had not begun during this thesis and therefore the presented concepts only represent the author's view of the upcoming features. Still, the functionalities should mostly apply with the descriptions introduced in this thesis. In addition, some of the most viable future developments were also reviewed in this thesis, most notably the new automatic fault isolation and restoration feature. Hence, a couple of solutions for the customers' needs were presented in this thesis but a lot of work still remain to be done to offer the best possible tools for fault management.

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APPENDIX A: THE BASIC STRUCTURE FOR THE CUSTOMER INTERVIEWS

This is the basic structure used in the customer interviews. First, feedback is requested, regarding the results of the fault simulations and then some background about the DSOs environment is discussed. In the main part, fault management has been generally divided into three categories; single fault situation, multiple fault situation and a major power disruption. For each situation, the fault management processes and development needs are discussed separately. However, this structure only forms the basis for the conversation and other fault management related matters were also discussed, if considered necessary.

<u>Results of the fault simulations</u>

- Based on your experience and intuition, do the results and conclusions presented in the material seem reasonable/reliable? For example does the used fault current information seem correct? What about the estimations of fault isolation times and KAH-reductions?
- Is it OK to include the data in the public part of this thesis? If there is anything that should be considered confidential, please point it out.

<u>Background: Network supervision and operation</u>

- How extensively are remote-controllable switches currently available in your network (e.g. how many RCDs per kilometer of network or feeder) and how do you estimate the situation in the future (trend)?
- Do you have fault indicators installed in your network? If yes, then what is the extent of their availability (e.g. amount of fault indicators per kilometer of network) and how do you estimate the situation in the future (trend)?
- What is your opinion on automatic experimental switchings (e.g. do you see any electrical safety related issues that would prevent the use of such automation in your network?). Please justify.

<u>Fault management in different fault situations</u>

- In this thesis, fault situations have been classified into three categories that are presented below. Does this classification seem reasonable to you/is similar classification used in your company?
    - o If not, please describe why and what kind of classification would be better/what kind of classification is used in your company.
- **Single fault situation/normal situation**
    - o How many operators are working in the NCC (in a normal situation)?

  - Please describe the progress of LV- and MV-fault management processes in your company and also try to emphasize the role of DMS600 in each phase of the process. What DMS functionalities do you consider most important in fault management?
  - Please describe the development needs for the current features of DMS600, reflecting to each phase of the fault management process. (If there are any)
  - What kind of new functions would you consider necessary or helpful in a normal/single fault situation?
- **Multiple faults**
  - Is the fault management process somehow different from the previous situation? If it is, then
    - What criteria is used to shift the organization to a different state? (e.g. amount of faults/unsupplied customers/something else)
    - Who makes the decision?
    - Please describe the fault management process briefly, emphasizing those phases that differ from the previous situation. (e.g. is the amount of personnel different in the NCC/do the responsibilities change/what is done differently). Again, please emphasize the role of DMS600 in the process.
    - Please describe the development needs for the current features of DMS600, reflecting to the fault management process in a multiple fault situation (if there are any)
    - What kind of new functions would you consider necessary or helpful in a multiple fault situation?
- **Major power disruption**
  - How does the fault management process change from the two previous situations?
    - What criteria is used to shift the organization into a major power disruption state? (e.g. amount of faults/unsupplied customers/something else)
    - Who makes the decision?
    - Please describe the fault management process briefly, emphasizing those phases that are different from the two previous situations. (e.g. the amount of personnel in the NCC/responsibilities/what is done differently). Again, please emphasize the role of DMS600 in a major power disruption.
    - Please describe the development needs for the current features of DMS600 in a major power disruption.
    - What kind of new functions would you consider necessary or helpful during a major power disruption?